Ontario Hydro

Bulk power rates proposed for 1980

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Chapter 1
INTRODUCTION

OEB ACT

1. Under Section 37a (2) of the Ontario Energy Board Act, Ontario Hydro is required to submit a proposal to change any of its rates or charges for its customers as defined by the Act, to the Minister of Energy not less than 8 months before the change is proposed to come into effect. The Minister is in turn required to refer the proposal to the Ontario Energy Board. Where the proposal is so referred, the Ontario Energy Board is required to give 20 days notice of and to hold a public hearing with respect to the proposal and is required to make a report or interim report thereon to the Minister of Energy at least 4 months before the proposed effective date of such change. Where the Board makes an interim report within such time it is required to make a final report as soon as possible thereafter.

2. Customer as interpreted by Section 37a (1) of the Act means an industrial customer of Ontario Hydro having an average annual power demand of 5,000 kilowatts or more or a municipal corporation or municipal electric utility commission.

HYDRO PROPOSAL

3. In accordance with the requirements of the Ontario Energy Board Act, Ontario Hydro's proposal to change rates effective January 1, 1980 was forwarded to the Minister of Energy in a letter dated April 30, 1979 (see Appendix 1). The proposal is to increase bulk power rates by an average of 9.9% for municipal utilities and for large industrial customers by an average of 7.8%.

4. The rate proposal is based on Load Forecast 790212 (February 12, 1979) and Financial Forecast 790420 (April 20, 1979). It incorporates the effect of revisions to the system expansion program in the period 1978-1987 as approved by the Hydro Board on April 9, 1979. The revisions to the program were made necessary by a further drop in forecast demand from that indicated last year.

5. In this submission, the evidence shows that the rates proposed are required to cover bulk power operating costs projected for 1980 to be $2,123 million and to provide net income of $192 million.

6. The proposed level of net income will result in a debt ratio of .862 with an interest coverage of 1.18.

7. In taking its position with respect to 1980 net income, the Hydro Board is acknowledging the continued need for restraint in a state of high general inflation. The Board has authorized the rate increase proposal at an absolute minimum established on the basis that the Corporation's financial soundness not be allowed to deteriorate further than the level now being forecast for the end of 1979, namely a debt ratio of .862.

SUBMISSION CONTENTS

8. Chapter 2, "Policy Matters", summarizes decisions representing new or changed policies, guidelines and practices, which affect costs or revenues in the year of review or could affect future periods.

9. In chapter 3, "Economic Outlook", a review of the economy at the macro level is given and in the latter part of the chapter the implications of the review are dealt with both in terms of Hydro's financial forecasting assumptions and the impact of the proposed rate increase on the economy.

10. The "Peak and Energy Demand" is covered in chapter 4 where Load Forecast 790212 is summarized. This forecast influences the energy production data used in revenue requirement calculations as well as revenue calculations. The effect of the forecast on capital construction has already been mentioned.

11. "Revenue Requirement" summary and details are developed in chapter 5. In this chapter which displays the results of Financial Forecast 790420, each component of the revenue requirement is analysed. Information is provided as to the assumptions made in the forecast and, where felt necessary, the revenue requirement item is explained and discussed relative to ancillary matters.

12. Chapter 6 on "Proposed Rates" explains that rates are established so that total estimated revenue will approximate the estimated bulk power revenue requirement. It shows the costs allocated to the Municipal Utilities and the Power District and within the Power District to Direct Industrial Customers and the Retail System. Detailed rate structures are given for both the municipal utility and direct customer classes. Finally, the development of forecast revenue to be generated by the rates is shown.

13. Chapter 7, "Financial Results", provides the financial statements reflecting the forecast costs and revenues along with some quantification and analysis of the accuracy of past financial forecasts.

14. An organization chart taken down to the level of positions reporting to vice-presidents is provided in Appendix 2.

Chapter 2
POLICY MATTERS

1. Matters of "policy", broadly defined so as to include procedures and practices as well as principles, have been summarized in this chapter. In this way, changes in these matters which affect costs or revenues in the period under review or which could affect later periods and which represent new or revised approaches in relation to those used in the 1979 bulk power rate submission are identified in one place. These items are referenced to the other chapters in which their effects are explained.

ACCOUNTING TREATMENT FOR BORROWED FUEL
(also see Chapter 5, Section B Energy Variable - Fuels)

2. Ontario Hydro has entered into agreements whereby it will borrow uranium concentrate. Under the terms of the agreements, Hydro will receive delivery of uranium concentrate and, in return, will be required to make rental payments for a specified period of time. At the end of this time it will return an equivalent quantity of uranium concentrate to the original suppliers. The estimated cost of the borrowed uranium concentrate, at the time it is received, is the present value of all associated expenditures. This present value cost is treated as a fuel cost in the same manner as the costs of purchased uranium concentrate.

ACCOUNTING POLICY FOR ADVANCES FOR PREPAYMENTS MADE UNDER FUEL SUPPLY CONTRACTS
(also see Chapter 5, Section D Fixed Charges - Interest)

3. Interest costs to Ontario Hydro resulting from capital advances and prepayments made under fuel-supply contracts, are capitalized until the supply facility is in-service and regular delivery of fuel begins, and are then charged directly to current operations as interest expense. The capitalized interest, together with any non-repayable advances or prepayments is amortized to fuel expense on the basis of fuel deliveries. Where fuel deliveries from an in-service supply facility are very irregular for reasons extrinsic to Hydro, the normal accounting treatment is modified to achieve a better matching of interest costs to fuel deliveries, while retaining the principles of the basic policy.

ACCOUNTING FOR THE DEFERRAL OF COMMITTED CAPITAL PROJECTS
(also see Chapter 5, Section D Fixed Charges - Interest & Depreciation)

4. For capital projects deferred more than one year, the capitalization of interest is stopped and the interest on debt required to finance the project is charged to current operations. Mothballing and caretaking costs resulting from the deferral decision are also charged to current operations. The mothballing costs are charged in the year that the decision is made to defer, but caretaking costs are recognized in the years they are incurred. Capital costs of deferred projects are amortized on a straight-line remaining-life basis. Amortization is assumed to begin at the date of deferral and is based initially on the depreciation rate for the appropriate class of asset.

ALLOCATION OF INTEREST EXPENSE
(also see Chapter 5, Section D Fixed Charges - Interest)

5. Interest is allocated to the bulk and retail systems on the basis of net assets less equity invested in each system. In the past, accounts receivable for each system were included in the base of net assets. The current forecast allocates interest relating to the accounts receivable of each customer class as a specific cost to that customer class. The remaining interest is allocated between bulk and retail, as previously, on the basis of net assets less equity invested, but excluding accounts receivable.

ALLOCATION OF HEAD OFFICE OVERHEAD COSTS

6. A revised corporate overhead policy was implemented January 1, 1979 as included in the 1979 bulk power rate proposal. The policy did not deal with procedures for allocating head office costs between bulk and retail systems. This matter was examined as part of the Electricity Costing and Pricing (ECAP) Study and specific recommendations were included in the ECAP report. In order to allocate all overheads on a similar basis, the corporate overhead policy has been extended to the allocation of overhead costs between the bulk and retail systems. According to this procedure head office costs are prorated to the bulk and retail systems

on the basis of the operation, maintenance and administration costs incurred by those systems. Applying this method has a similar effect to that of the ECAP Study recommendations but is a less detailed approach.

COSTING LOADS FOR ALLOCATION OF BULK POWER COSTS
(also see Chapter 4, Peak and Energy Demand)

7. Costing loads are determined by applying coincidence factors to delivered loads. Coincidence factors define the relationship between the peak load of a group of customers and the sum of the peak loads of the individual customers in the group. Coincidence factors are used to forecast the peak load of the power district, the direct class and the retail class. In previous forecasts, these coincidence factors were based on the average of the actual coincidence factors in the previous five years. The current forecast incorporates coincidence factors which are based on the five-year average and the trend of historical data. The bulk system costing loads are used to allocate bulk power system costs to municipalities and the power district. The power district costs are then allocated to direct industrial and retail customers on the basis of their class coincident peak loads.

ACCOUNTING POLICIES FOR FOREIGN EXCHANGE*

8. In November 1978 the Board of Directors approved an accounting policy effective January 1, 1979, for foreign currency transactions based on new recommendations from the Canadian Institute of Chartered Accountants (CICA). The major effect of this policy was to amortize unrealized exchange gains and losses associated with long-term liabilities to current operating costs over the remaining life of the related liabilities. In February 1979 the CICA suspended the effective date for application of the recommendations because the United States Financial Accounting Standards Board was considering changes to its procedures which are similar, and because of the severe financial impacts of the recommendations on Canadian companies. A new recommendation is not expected for some months and in light of this uncertainty the Board of Directors in April 1979 approved that the new policies be rescinded effective January 1, 1979, and that Ontario Hydro revert to its previous policy. The previous policy recognizes foreign exchange gains and losses as they materialize, which in effect means at the point a long-term liability is classified as being current, one year prior to maturity.

* This does not constitute a new policy different from that in effect at the time of the 1979 rate hearing. It is recorded here as a matter of interest to the Ontario Energy Board in view of its recommendation in the report to the Minister of Energy on HR7 (page 157, item 5).

Chapter 3
ECONOMIC OUTLOOK

BACKGROUND

1. A detailed long-term Economic Outlook is prepared annually each Fall by the Economics Division. Each quarter the short-term (2-5 yr) assumptions and forecasts are reviewed and updated where necessary. These forecasts constitute the base from which all other economic forecasts are derived by Ontario Hydro. Most of the economic assumptions used to develop the 1980 rate submission were taken from the Economic Outlook, Quarterly Review, dated January 1979. However, the forecast of the exchange rates and fuel costs were based on the April 1979 review.

2. The economic assumptions and forecasts supporting the rate submission are somewhat more pessimistic than those utilized in last year's submission. Economic growth is expected to be weaker, and inflation is expected to be higher and wage gains are anticipated to increase at a faster rate. The Canadian dollar is forecast to average \$0.88 in 1980. This compares to a forecast of \$0.93 in last year's submission. The revision was made due to higher inflation and dividend and interest payments, lower exports and continued political uncertainty.

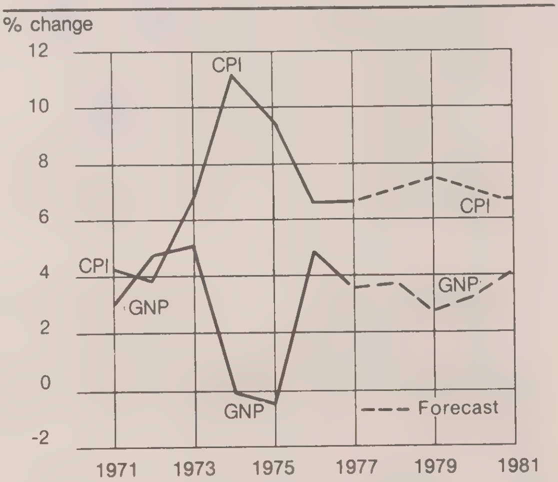
O.E.C.D.(1)

3. The rate of growth in real Gross National Product in the eight major OECD nations was 3.7% in 1978, up slightly from the 3.5% growth rate attained in 1977. Consumer spending, government expenditure and investment spending were generally weak, though the first two accelerated towards the end of the year in some countries. Growth in Europe and Japan resulted, in large part, from a strong foreign sector, whereas in the U.S. it was primarily due to growth in domestic demand. While some gains were made in employment, growth in the labour force overshadowed these gains causing unemployment rates to change little and even rise in some countries.

(1) OECD - Organization for Economic Co-operation and Development. The eight major OECD nations are Canada, the United States, Japan, Switzerland, West Germany, France, the United Kingdom and Italy.

4. The growth rate for the OECD nations is expected to fall off to 2.9% in 1979, but then rise to 3.3% in 1980, primarily reflecting stronger capital investment and consumer spending. It should rise again in 1981 to around 4.0%. The inflation rate is forecast to moderate from 7.1% in 1978 to 7.0% and 6.8% in 1980 and 1981, respectively. Historical and forecast data are shown in chart 3-1.

OECD — real GNP and CPI* **Chart 3-1**



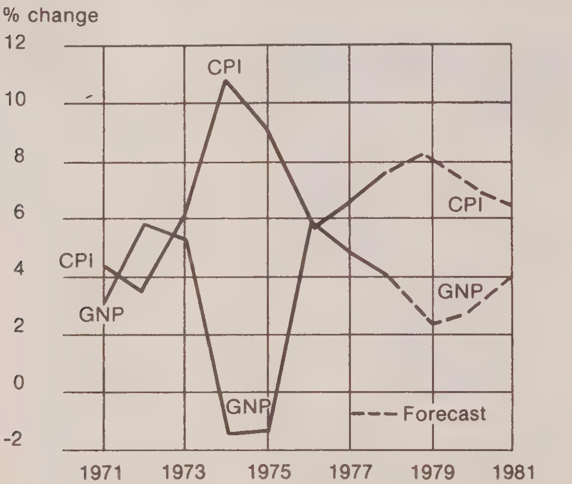
*Organization for Economic Co-operation and Development; gross national product; consumer price index

U.S.A.

5. Real Gross National Product in the United States increased 4.0% in 1978; down from the 4.9% growth attained in 1977. Real growth of 2.5% is forecast for 1979. Government spending will grow at a slower rate and consumer spending will likely weaken significantly. Business investment is expected to be the strongest sector. A slowdown in economic activity is forecast towards the latter part of 1979, as the government reacts to signs of overheating in an overstimulated economy. In addition, an acceleration of inflation accompanied by higher interest rates is expected in 1979. The rate of real growth is forecast to rise

to 3.0% in 1980 and 4.0% in 1981 - in response to anticipated fiscal stimulus and stronger capital spending. Inflation should fluctuate around the 7.0% level in the 1979-81 period. Historical and forecast data are shown in chart 3-2.

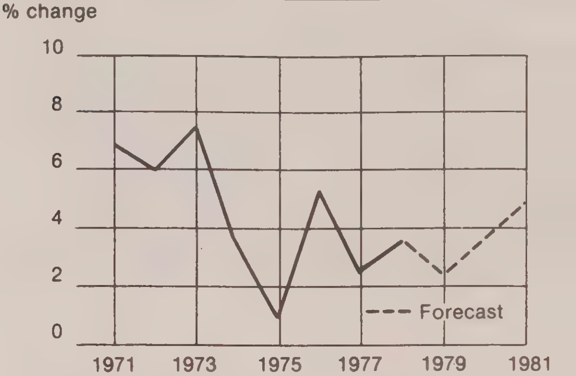
UNITED STATES — real GNP and CPI **Chart 3-2**



CANADA - GROWTH

6. Real economic growth increased by 3.4% in 1978, up from a growth rate of 2.7% in 1977. Real GNP is anticipated to increase by 2.5% in 1979, by 3.5% in 1980 and 5.0% in 1981. During this period, the economic cycle is expected to be characterized by: a continuation of the policy to constrain growth in the money supply by the Bank of Canada; moderate increases in total government expenditures; somewhat stronger consumer spending and investment in machinery and equipment; an export sector which should benefit from the low value of the Canadian dollar; and the influence of a recovery in the U.S. economy which is anticipated during the latter half of 1980. Historical and forecast data are shown in chart 3-3.

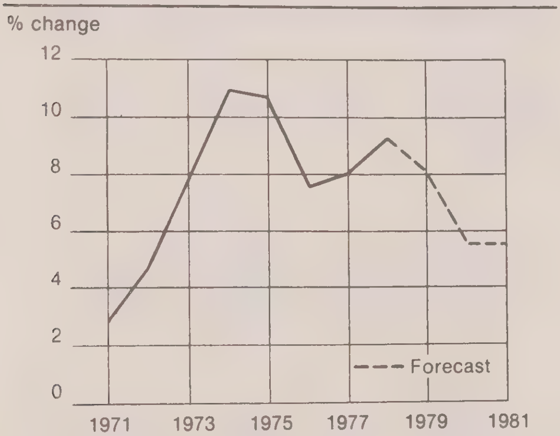
CANADA — real GNP **Chart 3-3**



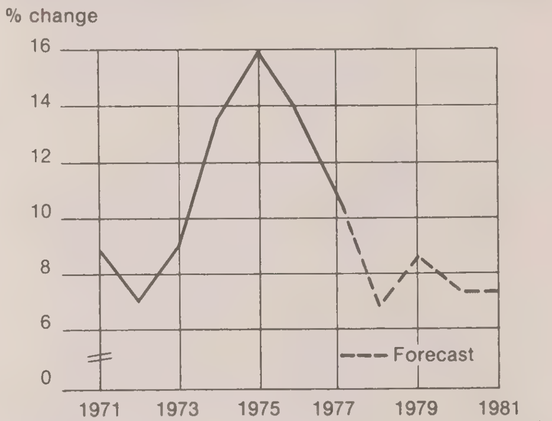
CANADA - INFLATION

7. The inflation rate in 1978 (as measured by the Consumer Price Index) averaged 9.0% and it is expected to average 8.0% in 1979. After this, the rate of increase is forecast to fall to 5.5% in both 1980 and 1981. A slight moderation of the inflation rate is expected in 1979 because of the lower federal sales tax, some moderation of food prices, a stable or slightly rising Canadian dollar and the continued existence of some excess production capacity. A slower growth of the CPI in 1980 and 1981 is anticipated due to slow economic growth in 1979 and early 1980 in Canada and the U.S.A., and a slightly rising dollar. However, the base rate of inflation will still fall in the 5.5% to 6.0% range because of rising energy prices and cost of living clauses in wage settlements. Historical and forecast data are shown in chart 3-4.

CANADA — CPI **Chart 3-4**



CANADA — average hourly earnings - manufacturing **Chart 3-5**



CANADA - WAGE RATES

8. Wage rates, as measured by average hourly earnings for manufacturing, increased 7.2% in 1978. They are forecast to rise by 8.5%, 7.5% and 7.5% in 1979, 1980 and 1981, respectively. Unions are expected to bargain forcefully for higher wage rates in 1979 as workers attempt to recoup their loss of real income experienced in 1977 and 1978. Some moderation in wage increases in 1980-81 is anticipated because of lower inflation rates. Construction labour wage rates are expected to exhibit a similar trend, but the increases will likely be slightly lower for the next three years. Historical and forecast data are displayed in chart 3-5.

CANADA - UNEMPLOYMENT

9. The sluggish economic forecast through to 1980 implies the continuation of high unemployment rates. Stronger economic growth in 1981 and beyond will cause unemployment rates to moderate. On the average, the unemployment rate should be 8.6% through the 1979-81 period.

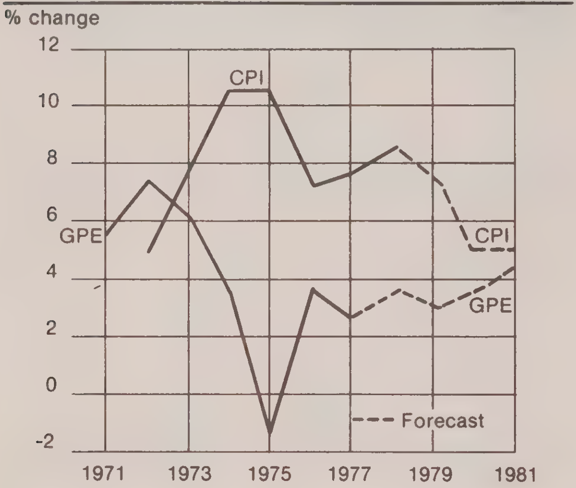
CANADA - CAPITAL MARKETS

10. Interest rates are forecast to remain high relative to historical levels. The Bank of Canada is assumed to continue constraining money supply growth during the period and heavy borrowings related to energy projects are expected to commence in the early 1980's. Long-term interest rates are expected to rise somewhat in 1979 and again in 1980 and 1981 due to the increased demand for investment funds and significant government borrowings.

ONTARIO

11. The rate of growth of real Gross Provincial Expenditure is expected to fall in 1979 to 3.0% from its 1978 level of 3.5%. Weak consumer spending combined with an end-of-year slowdown in the U.S.A. will be primarily responsible for this moderation in economic activity. Real growth is expected to increase by 3.5% in 1980 and by 4.5% in 1981 due to the positive impact on exports of the lower-valued Canadian dollar and improved business investment. Over the forecast period, the Consumer Price Index (Toronto) is expected to closely parallel increases in the Canadian inflation rate but to be generally lower than the national average. Historical and forecast data are displayed in chart 3-6.

ONTARIO — GPE and CPI Chart 3-6



COMMODITIES

12. The commodity groupings include steel, aluminum, lumber, copper and concrete. Prices for all of those commodities are determined by the domestic marketplace, cost inputs, and, for all but cement, international supply and demand factors. Commodities are a significant first stage input to most manufacturing processes, thus their demands and prices will be greatly influenced by the overall level of economic activity. For these materials, price increases are expected, generally, to fall below increases of the consumer price index in 1979 and then pick up to exceed inflation increases in 1980-81.

ENERGY

13. In order to meet the continuing energy demand, new fuel sources are being developed. This, together with the continued depletion of traditional sources of supply and the influence of various government policies, should create moderate real price increases in Canada for all fuels over the forecast period.

- Oil: Domestic crude oil prices are anticipated to reach world levels for oil delivered to Montreal by 1983. Thereafter, domestic oil prices are forecast to increase at the same rate as the international price of crude oil.

- Natural Gas: Recent indications of an improved reserve position together with market changes suggest that natural gas will maintain its present relationship of approximately 85% of the crude oil BTU equivalent price. The city-gate price of natural gas in Toronto is expected to increase parallel with the price of domestic crude.

- Thermal Coal: Canadian steam coal prices, at the mine, are expected to reflect general inflationary pressures. U.S. steam-coal prices, due to a softening in demand in the U.S. market and a potential surplus in mine production are not expected to increase faster than the general inflation rate at least until the mid-1980's.

- Uranium: Uranium prices are expected to show moderate increases in real terms.

FOREIGN EXCHANGE*

14. The Canadian dollar is forecast to average $0.855 in 1979 and $0.88 in 1980 following an average value of $0.877 in 1978. A gradual appreciation of the dollar from the $0.83 range in February is expected throughout the year with the year-end value around $0.87. Some strengthening is anticipated due to higher levels of trade, some moderation of inflation and some long-

* The forecast of exchange rates was based on the April 1979 Economic Outlook.

term capital flows. Continual strengthening is anticipated in 1980-1981 because of higher exports to the U.S.A. and increased inflows of long-term capital.

15. The Deutsche Mark and Swiss Franc are expected to depreciate against the Canadian dollar in the period 1979-81. This is expected as a result of: a rise in the Canadian/U.S. dollar exchange rate; some weakness of the $U.S./DM and $U.S./Swiss Franc as inflation in the respective countries rises. Inflation in Germany is forecast to rise from 3.5% in 1979 to 4.0% in 1981, and in Switzerland from 2.0% to 3.5%. This will be accompanied by real growth in the range of 3.5 - 4.0% in Germany and 2.0 - 3.5% in Switzerland. The average annual forecasts are shown in table 3-7.

Forecast foreign exchange rates — **Table 3-7**

Year	US$/C$	DM/C$	Sw/C$
1979	.86	1.62	1.42
1980	.88	1.69	1.47
1981	.90	1.80	1.52

IMPLICATION TO ONTARIO HYDRO

16. As indicated in the previous sections of this chapter, specific forecasts are produced, when required, for use in Ontario Hydro's estimating, controlling, planning and decision-making functions. These forecasts are developed within the framework and environment of the general economic outlook.

CONSTRUCTION FORECASTS - MATERIALS

17. Forecasts for prices of materials used in the Ontario Hydro capital construction program are categorized by indexes for generation projects, transmission systems and distribution construction. Generation project materials consist of those items used in constructing a generating station such as major equipment (pumps, boilers, motors and transformers) and construction materials (piping equipment, cable, steel and concrete). Transmission system materials consist of those items used in constructing transmission lines (mainly tower steel, conductor cable and concrete) and transformation and distribution stations (mainly switchgear, buildings and control instrumentation, meters and relays). Distribution construction materials consist of those items used in construction of low-voltage distri- bution systems (mainly poles, conductors and transformers).

18. Due to low construction activity over the past few years and resulting high inventory levels in many commodities, escalation rates for many products used in construction are currently at low levels. Consequently, inflation for construction materials purchased by Ontario Hydro is expected to be in the 6.5% to 7.0% range for 1979 and is expected to remain low in 1980. As construction activity in the economy begins to increase, the demand for industrial products and construction materials will also grow leading to higher-price escalation for steel products, concrete and lumber products. Accordingly price inflation to Ontario Hydro for these products is expected to be in the 8.0% to 8.5% range for 1981. These forecasts are outlined in table 3-8.

CONSTRUCTION FORECASTS - LABOUR

19. Forecasts for wages of labour employed by Ontario Hydro are also categorized in the same manner as for materials. Labour used in generation projects consists of local construction trades (electricians, steamfitters, carpenters and labourers) and Ontario Hydro engineering staff. Labour used in transmission systems consist of local construction trades (carpenters, electricians and labourers), Ontario Hydro trades (lineman, groundmen and truck drivers) and Ontario Hydro engineering staff. Labour used in distribution construction consists of Ontario Hydro staff.

20. Wage settlements received by the construction industry in Ontario in 1978 were low relative to previous settlements. These contracts were for two years and were generally negotiated for 5.5% - 6.0% per year across the province. It is anticipated that forthcoming settlements, in the spring of 1980 again will be two years in duration, but will be at higher rates of escalation due to expected increases in construction activity and due to real losses in income experienced during the previous contract. These forecasts are shown in table 3-8.

Escalation forecasts for capital construction **Table 3-8**

Annual average % change

Year	Generation Projects*		Transmission Systems		Distribution Construction Program	
	Material	Labour	Material	Labour	Material	Labour
1979	6.8	5.7	6.8	6.1	6.5	6.4
1980	7.5	7.1	5.7	7.3	6.0	7.4
1981	8.4	6.5	8.1	7.1	8.0	7.5

*According to weighting pattern for constructing a fossil-fuelled plant.

21. For Ontario Hydro engineering and clerical/technical staff, bargaining will be carried out against a background of wage dislocations caused by the A.I.B., real losses in wages in 1978, a slack economy and increased pressures by governments to restrain wage growth. As a result of these factors, Ontario Hydro wage increases are generally expected to lag behind those for the manufacturing sector in Ontario.

O.M.&A - OTHER COSTS

22. Escalation for O.M.&A Other Costs consists of changes in all costs to Ontario Hydro, other than labour, construction expenditures and fuel costs. Forecast escalation rates covering these costs are based on representative samples of weighted items for administrative services, such as: computer costs; office equipment and supplies; furniture; building maintenance; rental and taxes; contracted services and travel costs; and expenses incurred in regional operations such as equipment replacement, chemical treatments for rights of way, and operation and maintenance of the transport and work equipment fleet.

23. The escalation forecast for these costs is shown in table 3-9. Generally, much of the equipment in this category has experienced a tremendous amount of technological change over the past decade, for example, computer equipment, office machinery and telecommunications equipment. Consequently, price escalation for this type of equipment has been low and it is expected that this trend will continue into the 1980's.

O.M.&A - LABOUR RATES

24. Escalation for O.M.&A, (Operations, Maintenance and Administration) labour rates consists of changes in total compensation as paid by Ontario Hydro. Accordingly, escalation of O.M.&A labour rates includes wage increases to employees and any changes in fringe benefits.

25. Ontario Hydro's forecast of O.M.&A cost changes is shown in table 3-9. These increases are generally premised on the same assumptions as indicated for Ontario Hydro staff under Construction Forecasts - Labour. The development of these forecasts is based on general economic activity and is related to assumptions made concerning price inflation in the economy, productivity, collective bargaining trends and other local and public sector wage trends.

Forecasts of Ontario Hydro O.M.&A. cost changes **Table 3-9**

Annual % change

Year	Other Costs	Labour Compensation
1979	6.1	6.4
1980	5.6	7.6
1981	6.1	7.7

INTEREST RATES

26. In forecasting Ontario Hydro's interest rates, consideration is given to the relationship of Hydro rates to the marketplace, any expected changes in the mix of maturities and the capital markets used. In the case of the first forecast year, known strategic timing of issues, based on cash forecasts, are also incorporated. Resulting forecasts are listed in table 3-10.

Ontario Hydro interest rate forecasts — **Table 3-10**

per cent

Year	SHORT –in Canada	MIX –Canada & Foreign	LONG –in Canada	LONG –in U.S.A.
1979	10.25	10.00	10.00	9.50
1980	9.00	10.00	10.25	9.50
1981	9.00	9.75	10.25	9.50

FUEL COST ESCALATION

27. Specific forecasts of Hydro fuel costs are developed from the assumptions about the various energy and economic price movements contained in the Background section. This information is supplemented by forecasts of Hydro demand by fuel type, contractual requirements and specific supply and demand factors for each fuel type. The forecasts are prepared and expressed as an annual average percentage change, as shown in table 3-11. The changes in the nuclear-fuel costs are discussed in the Fuel section of Energy Variable in chapter 5.

Forecast of unit-cost escalation –fuel purchases — **Table 3-11**

Annual average % change

	Forecast 1979	1980	1981
Coal	8.3	3.8	5.2
Petroleum	19.2	20.2	10.3
Nuclear	28.8	–23.5	22.4
Water rentals	8.0	5.5	5.5

IMPLICATION OF THE RATE INCREASE ON THE ECONOMY

28. The percentage of average-family income spent on electricity increased marginally from 1.1% in 1971 to 1.3% in 1977. The percentage of average family income spent on food, furniture and automobiles is estimated to be 16.0%, 6.5% and 12.0% respectively in 1977. In 1979, the percentage of average-family income spent on electricity is expected to remain the same at 1.3%. The percentage spent on food, furniture and automobiles is estimated to be 17.5%, 6.3% and 13.0% respectively in the same year.

29. The proposed 1980 bulk power rate increase is expected to have a minimal impact on the national and provincial economies as shown in table 3-12. The higher costs of electricity will likely result in a minor decline of real output during the third and fourth quarters of 1980. It is not expected to have any impact on real growth in 1981. Both the consumer price index and the industry selling price index are slightly higher in 1980 and 1981.

Impact on the economy — **Table 3-12**

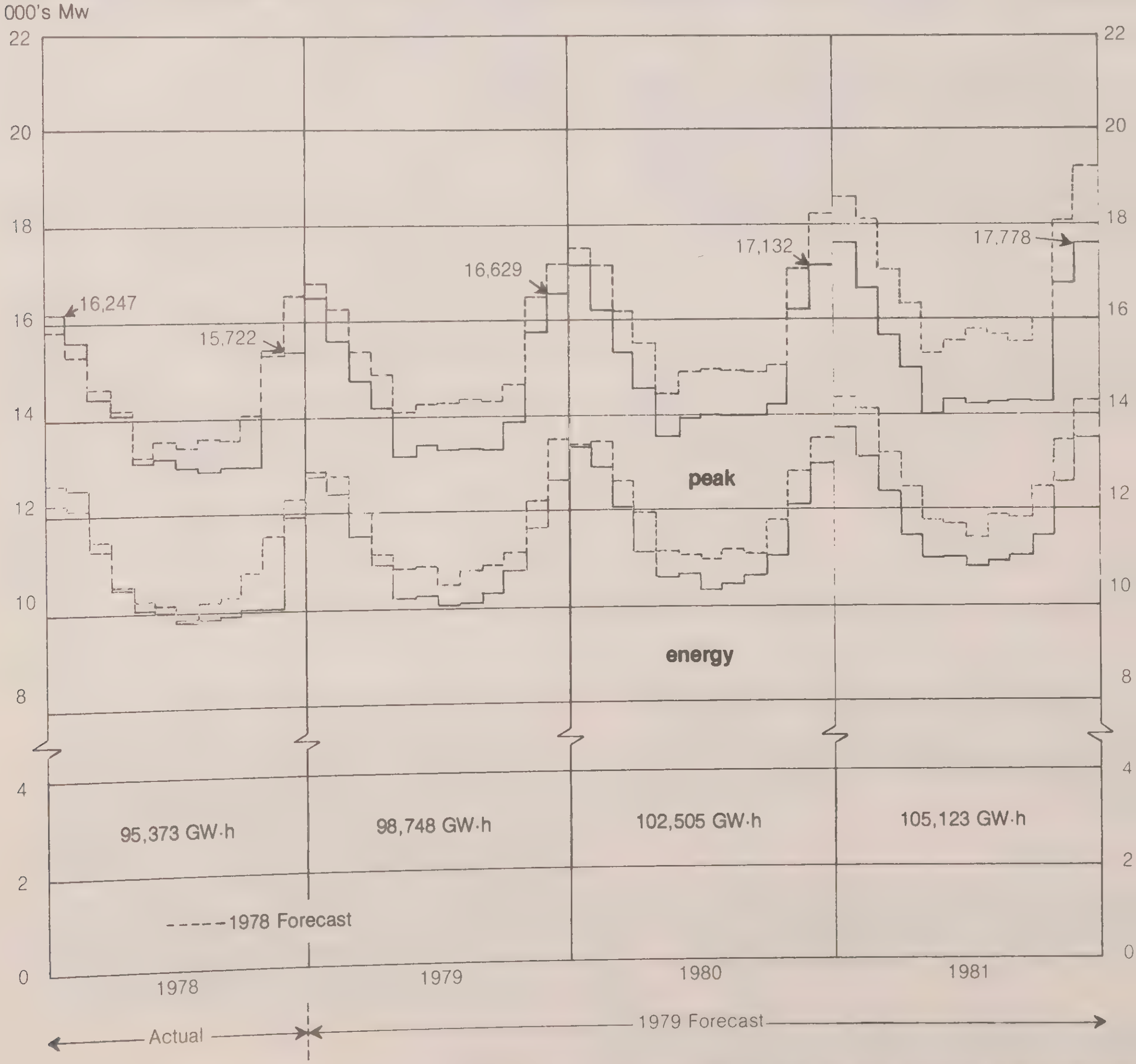
Changes to percentage points

	1980 Qtr. 1	1980 Qtr. 2	1980 Qtr. 3	1980 Qtr. 4	1981
Real GNP	—	—	–0.1	–0.1	—
Unemployment	—	—	0.1	0.1	0.2
GNP deflator	0.2	0.4	0.4	0.4	0.4
Consumer price index	0.1	0.3	0.3	0.3	0.4
Industry selling price index	0.1	0.1	0.1	0.1	0.2

Chapter 4
PEAK AND ENERGY DEMAND

1. Chart 4-1 shows monthly demands for peak and energy. The energy demands are expressed as a rate, called average megawatts, which is the number of megawatt hours of energy generated in each month divided by the number of hours in that month. Also shown for comparison purposes is the 1978 forecast.

1979 forecast of all systems monthly demand — peak and energy **Chart 4-1**



2. The peak and energy demands experienced in 1978 were below forecast for the most part during the second half of the year.

	December Peak (MW)	Annual Energy (Av. MW)
Actual - 1978	15,722	10,887
Forecast - 1978	16,557	11,035
% error	-5.0	-1.34
Actual - 1977	15,677	10,600
% change	+.29	+2.70

3. The December peak in 1978 was depressed due to the absence of normal peak condition weather and was little changed from the November value of 15,633 MW (compared to the forecast of 15,572 MW). Demands in general were depressed by strikes with an estimated effect in the order of 200 MW. Table 4-2 compares the December peaks in forecast 790212 (February 12, 1979) and forecast 780213 (February 13, 1978).

forecast and the price outlook for electricity, gas, and oil. The models yield the following elasticities.

	Elasticities		
	December		January
	Short-term	Long-term	Short-term
Demand charge	- .41	-.46	- .20
Energy charge	- .13	-.17	.03**
Real output/ employee	1.12	1.34	.78
Employment	1.45	1.26	1.80
Oil price	- .13	-.10	- .37
Gas price	- .04	-.04	- .02**
Temperature*	- .00013**	-	

Variables (except temperature) are logarithms
* 5 pm temperature in Farenheit
** not statistically significant

Comparison of 1979 and 1978 forecasts **Table 4-2**

	Peak (MW)			Energy (Av.MW)		
	#790212	#780213	%	#790212	#780213	%
1979	16,629	17,398	−4.4	11,200	11,652	−3.9
1980	17,132	18,314	−6.5	11,604	12,202	−4.9
1981	17,778	19,304	−7.9	12,001	12,842	−6.5

4. For the calendar year 1978, once again the peak occurred in January. The winter peak of 16,252 MW occurred on January 15, 1979, with February 15, 1979 only 18 MW less during extremely cold weather.

EAST SYSTEM

5. The new regional estimates for the 1979 forecast are slightly above the 1978 forecast for the year 1979 and lower thereafter, reflecting a lower expected growth rate.

6. Alternative forecasts were provided by mathematical models of East System Peak which incorporate the Ontario Hydro economic

7. The December model incorporates estimates of long-term elasticities which give considerable insight into the response of demand to various stimuli. The long-term elasticity for output/employee, 1.34, is higher than the short-term, 1.12, while for employment the reverse is true with the long-term estimate being 1.26 which is lower than the short-term estimate, 1.45. This is in accord with the expected effect of increased economic activity where the short-term response is higher employment using existing less efficient equipment; and the long-term response is capital investment in new, perhaps labour-saving, equipment.

8. The short-term electricity price elasticities for the December model are -.41 for the demand charge and -.13 for the energy charge (as both affect peak demands). The long-term elasticities are respectively -.46 and -.17, or farther from zero as predicted from theory.

9. The short-term impact of an oil price increase is negative, suggesting that oil and gas are complements in the short-term. In the long-term one would expect them to be substitutes, and therefore the lower long-term elasticity is consistent from the model point of view.

10. Table 4-3 compares the regional estimates for December with the model results. The unallocated load is the difference between the regional estimates and forecast 790212.

12. As shown in table 4-4, forecast 790212 levels for January, compared with the results of the January model, are relatively close while the rates of growth differ. The January model is included because the winter peak has occurred in January for the past three years. The forecasts for 1983 to 1985 are lower than the results indicated by the model, but this reflects the smoothing assumsumption made about the course of the load growth.

13. Unallocated load is a measure of the judgment exercised on the regional estimates. The exercise of judgment was conditioned by the following factors.

- The starting point of the regional estimates appears to be too high as indicated by a forecast growth of 8% in 1979.

Model results and the forecast—December **Table 4-3**

MW

December	Regional Estimates	% Increase	Unallocated Load	Forecast 790212	% Increase	Model	% Increase
1978	14,940*					15,300**	
1979	16,525	8.0	−765	15,760	3.0	15,543	1.6
1980	17,342	4.9	−1109	16,233	3.0	15,023	−3.3
1981	18,338	5.7	−1456	16,882	4.0	15,234	1.3
1982	19,168	4.5	−1399	17,769	5.25	16,081	5.6
1983	20,059	4.6	−1358	18,701	5.25	17,056	6.1
1984	20,988	4.6	−1305	19,683	5.25	18,278	7.2

*Actual
**Adjusted for strikes.

11. The model constructed for January displayed in paragraph 6, shows somewhat smaller electricity price and real output/employee elasticities, and neither the energy charge nor gas price estimates are statistically significant. However, the combined employment and real output/employee elasticities are consistent with the December model, and the demand price elasticity is consistent with other short-term estimates. There are indications that the long-term price elasticities may be comparable in the two models.

Model results and the forecast—January **Table 4-4**

MW

January	Forecast 790212	% Increase	Model	% Increase
1980	16,280	4.0	16,241	3.7
1981	16,769	3.0	16,462	1.4
1982	17,439	4.0	17,431	5.9
1983	18,355	5.25	18,503	6.1
1984	19,318	5.25	19,862	7.3
1985	20,333	5.25	21,406	7.8

- The high rates of growth indicated by the models in 1982-1984 depend critically upon the timing and magnitude of an increase in economic activity. There is considerable uncertainty about both timing and magnitude.

- The very low rates of growth shown by the model reflect large real price increases and a very weak economy.

- The model for January demands reveals considerably less discrepancy under identical assumptions about the external and pricing environment.

14. The forecast is therefore a judgment based on these factors. The necessity to make such a judgment in the first instance is an indication of increased uncertainty.

WEST SYSTEM

15. The forecast for the West System was based on the regional estimates with changes in forecast transmission losses on the system which accounted for most of the error in the 1978 forecast. This does not affect the load delivered to wholesale-system customers.

RISKS AND UNCERTAINTIES

16. There is also uncertainty about the magnitude of changes in both the current and future real prices of electricity. As indicated above, the unknown effect of the Anti-Inflation Program rebates and their cessation contribute to the existing uncertainty about the forecast. Estimates of the impact and timing of price changes are improving, but remain subject to a wide margin of error.

17. There are signs of increasing investment in the economy (the first for several years). These investments in the short term contribute to increased output and employment and in the longer term should contribute to productivity improvement.

18. Recent events in Iran have considerably clouded not only the oil price outlook, but also the North American response to it. In addition, estimates of the availability of both oil and gas from North American sources have been revised sharply upward.

19. The December model was used to generate alternative scenarios. A high-growth scenario with real prices as forecast and the economy operating at potential in 1985, indicates a sustained load growth of 6.4% over the period 1980-1985. If increased growth reduces real unit price increases to zero, sustained load growth could be as high as 8%.

20. A low-growth scenario, with no further deterioration in unemployment and only modest gains in real output/employee, indicates a sustained load growth rate of 3.3% in the 1980-85 period, and this would be lower still if lower growth led to higher-unit prices.

21. Table 4-5 gives the 50% confidence limits for forecast 790212. There is an equal probability that actual demands will fall inside or outside the range shown.

50% confidence limits for forecast 790212 **Table 4-5**

MW

		Range		
Winter	Forecast	Lower–Upper	% Forecast*	Average annual growth rate
1979/80	17,157	16,742-17,582	4.9	3.0-8.2
1980/81	17,646	17,045-18,268	6.9	2.4-6.0
1981/82	18,346	17,584-19,140	8.5	2.7-5.6

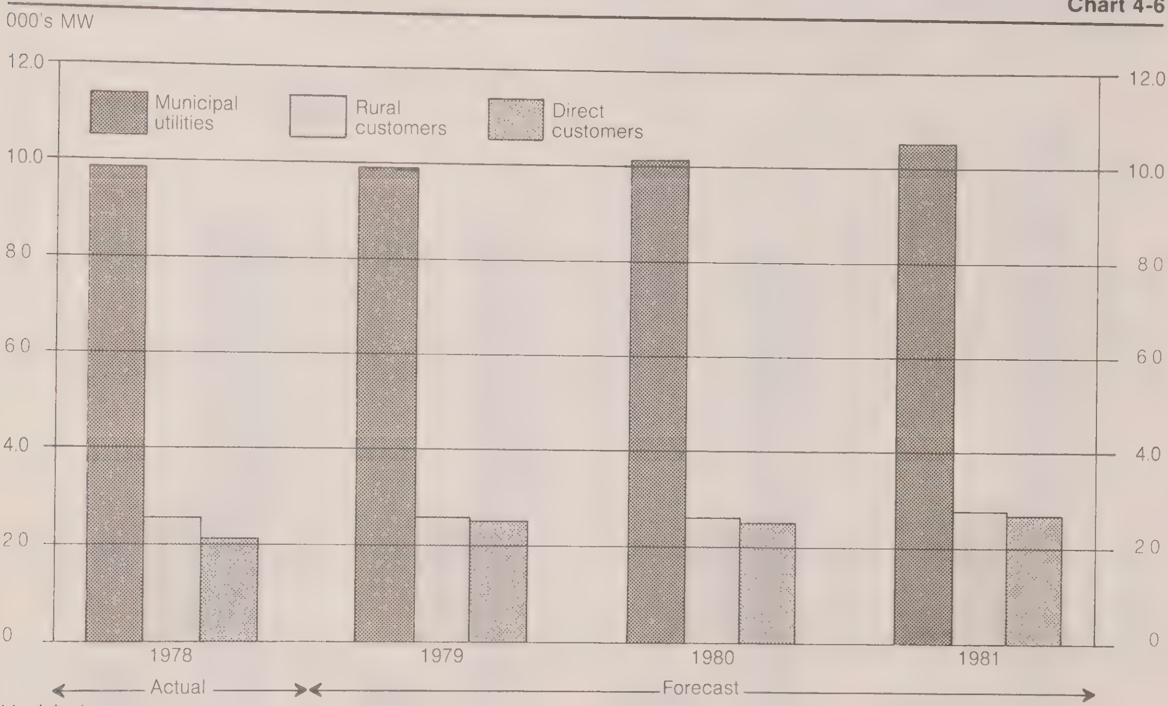
$*\frac{\text{Upper–Lower}}{\text{Forecast}} \times 100$

BULK POWER DELIVERIES

22. The load forecast builds up estimates of system primary peak and energy demands at the generators from forecasts of billing peak and energy loads at the point of delivery to bulk power customers. This involves the addition of losses to bulk energy sales and for peak it also requires an estimate of diversity, which is the difference between the sum of individual non-coincident peak loads and the maximum simultaneous delivery rate for energy at these bulk delivery points. Charts 4-6 and 4-7 show bulk power deliveries by customer class for peak and energy.

Bulk power delivered

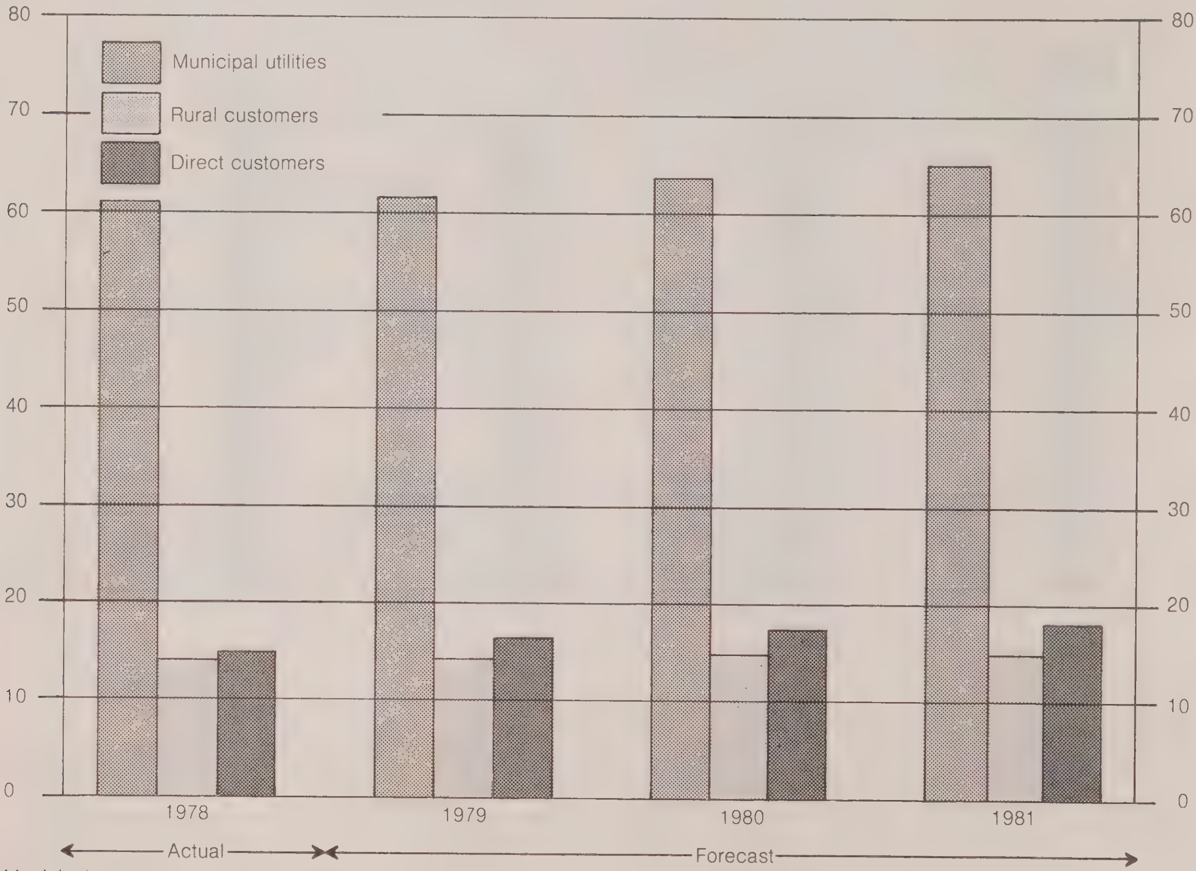
Chart 4-6



	1978	1979	1980	1981
Municipal utilities	9,849	9,881	10,110	10,280
Rural customers	2,474	2,516	2,550	2,722
Direct customers	2,148	2,360	2,504	2,668
Total	14,471	14,757	15,164	15,670

Bulk energy delivered **Chart 4-7**

000's GW.h



	1978	1979	1980	1981
Municipal utilities	61,252	61,968	63,913	65,030
Rural customers	13,911	14,117	14,352	15,266
Direct customers	14,696	16,218	17,338	18,307
Total	89,859	92,303	95,603	98,603

23. Bulk energy forecast for all systems is related to customer deliveries in table 4-8.

24. The forecast of monthly billed peak loads and energy at the point of delivery to the bulk power customers is developed by the class of customer.

Municipal utilities

- Peak and energy delivered to each individual municipal utility.

Direct customers (over 5000 kW)

- Peak and energy delivered to each individual direct customer. A minor adjustment is made for losses on lines which are specific to direct customers.

Rural customers

- Peak and energy delivered at bulk to the individual delivery points of the Rural areas. A minor adjustment is made for losses on lines which are specific to the rural customers.

25. These loads form the basis for (a) calculating estimates of bulk power revenues and (b) for determining the cost of power allocation to the customer classes, as shown in table 4-9 for the year 1980.

26. Individual municipal utility peak loads, the group peak load of the power district, the peak load of the direct class and the peak load of the rural class are required for the allocation of costs.

27. While the peak loads of individual municipal utilities are developed in the load forecast, group peak loads of the power district, the direct class, and the rural class are not. Only the peak loads of individual direct customers and of rural areas are available in the load forecast. Estimates of the peak loads of these classes as well as of the power district itself are calculated from the forecasts of individual peak loads. Each calculation entails using a factor which quantifies the relationship between the sum of the peak loads of the individuals in the group, and the peak load of the group as a whole. This is called a coincidence factor.

28. The current forecast of coincidence factors is based on a combination of the average of the coincidence factors in the past five years and the trend of coincidence factors in the last ten years. Table 4-10 illustrates the coincidence factors obtained for the power district based on the five-year average, the trend analysis and the combined methodology.

29. Table 4-11 demonstrates the calculation of the power district group peak load by

Total energy forecast and customer deliveries — Table 4-8

GW.h

	Actual	Forecast		
	1978	1979	1980	1981
Total energy – all systems	**95,373**	98,748	102,505	105,123
Transmission losses*	**4,830**	5,657	5,806	5,398
Primary deliveries	**90,543**	93,091	96,699	99,725
Internal sales	**699**	803	1,112	1,140
	89,844	92,288	95,587	98,585
Non-common lines losses	**15**	15	16	18
Customer-billed energy	**89,859**	92,303	95,603	98,603

*Includes non-common line losses

1980 forecast billing peak and energy — Table 4-9

(MW)	Billing peak including internal use	Effect of interclass transfers	Less internal loads	Adjustment for line losses	Peak for revenue requirement
Municipal utilities	9,996	114	—	—	10,110
Direct customers	2,649	—	(148)	3	2,504
Rural customers	2,681	(127)	(6)	2	2,550
	15,326	(13)	(154)	5	15,164

(GW.h)	Energy including internal loads	Effect of interclass transfers	Less internal use	Adjustment for line losses	Energy for revenue requirement
Municipal utilities	63,202	711	—	—	63,913
Direct customers	18,403	—	(1,075)	10	17,338
Rural customers	15,094	(711)	(37)	6	14,352
	96,699	—	(1,112)	16	95,603

application of the power district coincidence factor to the sum of individual peak loads. Table 4-12 demonstrates the calculation of direct and rural group peak loads by application of the appropriate coincidence factors.

30. The monthly demand - peak and energy shown on chart 4-1 pertains to generation requirements, whereas the sum of individual peak loads shown on table 4-11, is the sum of the average monthly peaks of individual municipal utilities, direct customers and rural areas.

Power district coincidence factors — Table 4-10

Year	Five-year average	Trend	Forecast
1979	.8560	.8505	.8533
1980	.8560	.8488	.8524
1981	.8560	.8471	.8516

Municipal utility and power district group peak loads for 1980 — Table 4-11

MW

	Sum of individual peak loads	Coincidence factor	Group peak load
Municipal utilities	10,110	1.0000	10,110
Power district	5,054	0.8524	4,308
Total	15,164		14,418

Direct and rural group peak loads for 1980 — Table 4-12

MW

	Sum of individual peak loads	Coincidence factor	Group peak load
Direct customers	2,504	0.8572	2,146
Rural customers	2,550	0.8996	2,294
Total	5,054		

Chapter 5
REVENUE REQUIREMENT

A. Summary

1. Ontario Hydro's revenues must cover annual operating costs and provide sufficient net income to maintain the financial soundness of the Corporation including compliance with specific debt retirement provisions of the Power Corporation Act.

2. The components of the bulk power revenue requirement are

- Energy variable costs
- Operation, maintenance and administration
- Interest (Fixed charges)
- Depreciation (Fixed charges)
- Net income
- Other (Secondary revenue, Internal sales, Bruce steam transfer)

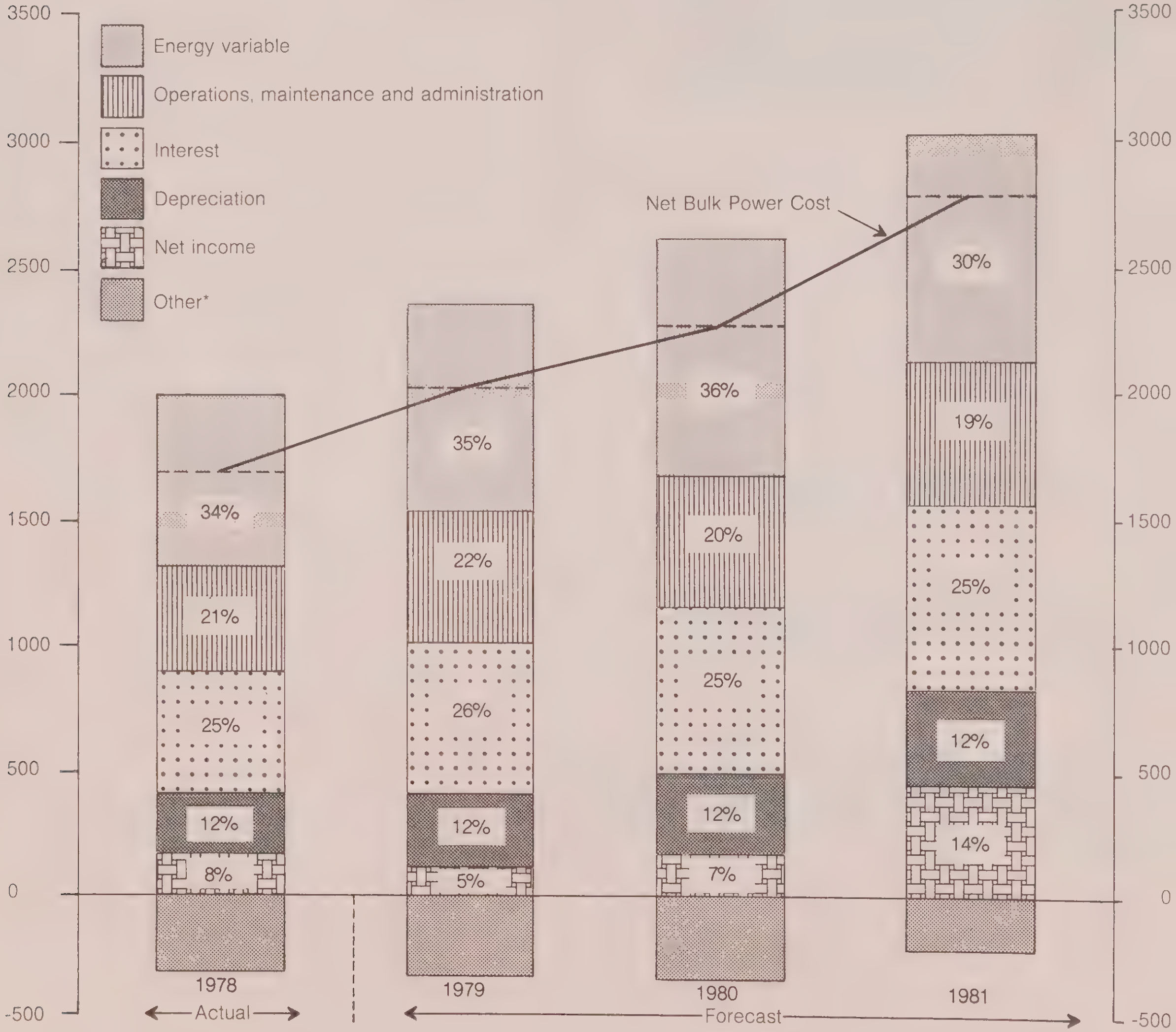
3. Chart 5A1 displays the percentage of the gross bulk power cost that each component represents for each year of the period under review.

4. The bulk power revenue requirement indicated in Financial Forecast 790420 is detailed in table 5A2. This table also shows the chapter section in which each item is covered.

Bulk power cost components

Chart 5A1

$ millions



*Secondary and internal sales and Bruce steam transfer

Bulk power revenue requirement **Table 5A2**

$ millions

	Actual		Forecast	
	1978	1979	1980	1981
Energy Variable (Section B)				
Fuel—coal, c.t. oil, etc.	**356**	522	611	549
—oil	**42**	41	52	88
—gas	**45**	41	28	29
—nuclear	**48**	63	65	75
—NPD steam	**4**	4	5	5
Sub total fuel	**495**	671	761	746
Commissioning				
—fossil	**18**	—	2	1
—nuclear	**4**	4	2	14
Sub total commissioning	**22**	4	4	15
Power purchases				
—Douglas Point	**7**	10	24	24
—Contract and economy	**91**	74	80	69
Sub total power purchases	**98**	84	104	93
Nuclear agreement-payback	**47**	52	64	65
Water rentals	**18**	20	20	21
Total Energy Variable	**680**	831	953	940
Operation, maintenance and administration (Section C)	**410**	503	509	562
Property taxes (Section C)	**13**	14	15	16
Fixed Charges (Section D)				
Interest	**508**	628	668	752
Depreciation	**238**	290	320	364
Total Fixed Charges	**746**	918	988	1116
Net Income (Section E)				
Debt retirement	**106**	127	147	165
Stabilization of rates	**51**	(19)	45	265
Deficit recovery	**3**	4	—	—
Total Net Income	**160**	112	192	430
GROSS REVENUE REQUIREMENT	**2,009**	2,378	2,657	3,064
Secondary revenue (Section F)	**(289)**	(294)	(291)	(202)
Internal sales (Section G)	**(12)**	(15)	(23)	(27)
Bruce steam transfer (Section H)	**(8)**	(19)	(28)	(27)
	(309)	(328)	(342)	(256)
NET REVENUE REQUIREMENT	**1,700**	2,050	2,315	2,808

NOTE: The applicable revenue requirement figures shown in this table, are repeated for convenience, together with the year to year change, at the beginning of each section and sub-section of Chapter 5.

B. Energy Variable

GENERAL

Energy variable — **Table 5B1**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**680**	831	953	940
Change from previous year				
Fuel	**53**	176	90	(15)
Commissioning	**(30)**	(18)	—	11
Power purchases	**22**	(14)	20	(11)
Nuclear payback	**(3)**	5	12	1
Water rentals	**3**	2	—	1
	45	151	122	(13)

1. Energy variable costs are fuel and equivalent expenses, such as water rentals, commissioning and purchased electricity costs, which vary with the quantity of energy produced. They also include nuclear payback which is dependent, by the terms of the agreement with Atomic Energy of Canada Limited (AECL) and the Province of Ontario, on the relative performance and costs of Pickering and Lambton. As indicated in table 5B1, the total energy variable costs for 1980 are expected to increase by $122 million over 1979.

ENERGY

2. The quantity of energy produced from each of the various resources, shown in table 5B2, depends upon a number of factors, including

- primary energy demand in Ontario
- availability of economically attractive energy from external systems
- performance of Ontario Hydro's generating units
- the market for secondary sales

3. The primary energy delivered by the bulk electricity system for 1980 is forecast to increase by 3608 GW·h over 1979. This increase is met partly by a 911 GW·h increase in nuclear generation. The remainder comes from increased fossil generation.

4. Energy produced from hydraulic resources depends primarily on the estimated availability of water. Experience has shown that actual water conditions can vary widely from forecast. For example, in 1977 because of extremely poor water conditions in parts of the province, actual hydraulic output was 3548 GW·h less than forecast for that year.

5. The good performance of nuclear plants in 1976 to 1978 inclusive, is expected to continue. Electrical capacity and capability factors for Pickering NGS and Bruce NGS are shown in table 5B3. Both types of factors are presented because comparison of capability factors is a more appropriate measure of relative performance of the two plants.

6. For Pickering NGS, the forecast capacity factors are higher than the five-year rolling average - 1974 to 1978. The five-year average was affected by the extended outages experienced during this period to correct pressure tube problems.

7. Bruce capability factors are expected to be lower than those for Pickering because Bruce has not yet reached maturity and unit-outage rates will be comparatively high as in any new plant, particularly when the Bruce units are of a larger size.

8. For Bruce NGS A, the capacity factors are substantially lower than the capability factors because electricity production is limited by the following.

- Steam that could be used for electric energy production will be diverted for the production of heavy water.
- Transmission limitations arising from construction delays of 500 kV lines will restrict deliveries to the bulk electricity systems.

Ontario Hydro electric energy production

Table 5B2

GW.h

	Actual 1978	Forecast 1979	Forecast 1980	Forecast 1981
Hydraulic	**35,834**	36,449	35,969	35,705
Nuclear				
Pickering	**15,834**	15,335	15,372	17,748
Bruce	**12,649**	15,348	15,567	17,687
Douglas Point*	**469**	578	1,221	1,171
NPD	**136**	139	151	140
	29,088	31,400	32,311	36,746
Fossil				
Coal	**25,725**	31,974	34,691	29,666
Gas	**2,079**	1,608	974	.902
Oil	**1,724**	1,175	1,285	2,159
CTU	**15**	29	21	14
	29,543	34,786	36,971	32,741
Commissioning	**1,695**	296	281	948
External resources				
Purchases	**9,394**	5,535	5,684	4,727
Other receipts	**1,179**	1,056	906	906
	10,573	6,591	6,590	5,633
Total resources	**106,733**	109,522	112,122	111,773
Secondary deliveries				
Sales	**10,393**	10,000	9,000	6,000
Other	**967**	774	617	650
	11,360	10,774	9,617	6,650
Primary resources	**95,373**	98,748	102,505	105,123
Transmission losses**	**4,830**	5,657	5,806	5,398
Primary deliveries	**90,543**	93,091	96,699	99,725

*Douglas Point NGS is owned by AECL but operated by Ontario Hydro.
**Transmission losses for 1979 and 1980 have been increased by 637 GW.h and 589 GW.h respectively. These adjustments were made to incorporate the transmission losses resulting from inadequate transmission facilities from Bruce NGS.

9. The year-to-year variability of the Bruce electrical capacity factors, shown in table 5B3, is due to changes in the relative weight of the factors described in paragraph 8. Specifically, the supply of steam to the heavy water plant is forecast to increase in 1980 and reduce in 1981; transmission limitations are forecast to impose a constraint in both 1979 and 1980, and should disappear in 1981; and outage rates are expected to be less than 1979 in both 1980 and 1981.

Nuclear capability factors and electrical capacity factors — Table 5B3

	Actual 1974 to 1978 Average	Forecast 1979	Forecast 1980	Forecast 1981
Pickering NGS capability factor	80	85	85	83
Bruce NGS capability factor	76*	71	74	76
Pickering NGS electrical capacity factor	80	85	85	83
Bruce NGS electrical capacity factor	70*	60	60	68

Capability factor – is the ability of the station to produce energy (electricity or steam) divided by the energy produced if the plant is perfect.

Electrical capacity factor – is the actual electrical energy produced divided by the energy produced if the plant is perfect.

*Average for 1977 and 1978 only.

10. The Bruce to Milton 500 kV transmission lines are assumed to be in-service as of January 1, 1981. The effect of not having these lines available to operate in 1980 at 500 kV is an estimated increase of $26 million in the bulk power revenue requirement.

11. For Douglas Point NGS, the electrical energy production for 1980 is forecast to increase by 643 GW·h over 1979. This increase reflects a return to normal operating conditions.

12. The level of energy received from external resources is virtually unchanged in 1980 from 1979. This is covered in more detail later in this section under Power Purchases.

13. In 1978, the coal miners in the United States were on strike during the first part of the year. These circumstances provided the opportunity to export considerable amounts of energy. Total secondary deliveries are forecast to decline by 586 GW·h in 1979 and an additional 1157 GW·h in 1980. Secondary sales are more fully discussed in section F of this chapter.

* * * * *

FUELS

Fuels* — Table 5B4

$ millions

	Actual 1978	Forecast 1979	Forecast 1980	Forecast 1981
Revenue requirement	**495**	671	761	746
Change from previous year				
Coal	**45**	166	89	(62)
Oil	**18**	(1)	11	36
Gas	**(33)**	(4)	(13)	1
Nuclear	**22**	15	2	10
NPD steam	**1**	—	1	—
	53	176	90	(15)

*Used for generation at in-service stations.

FUEL CONSUMPTION COSTS

14. The revenue requirement for fuels includes fossil (coal, oil and gas) and nuclear fuel costs associated with the generation of primary and secondary energy from in-service units and the costs related

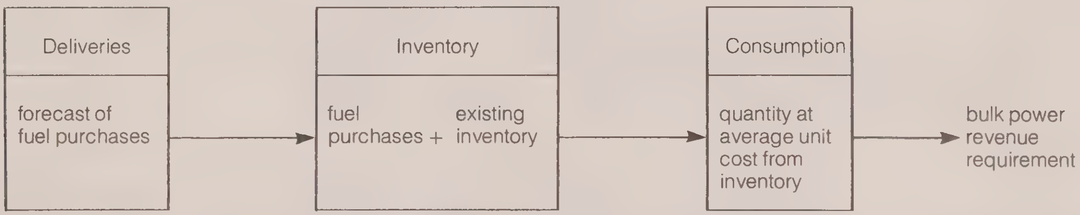
to the purchase of steam from AECL at the NPD generating station.

15. The 1980 revenue requirement for fossil and nuclear fuels is derived from the projected cost of the fuels consumed from station inventories. The average unit cost of fuels in inventory takes into account the forecast cost of fuels to be delivered to the generating stations. Chart 5B5 shows in diagrammatic form the flow of fuel purchase quantities and costs through the station inventories to the fuel cost component of the bulk power revenue requirement.

and general fuel escalation, contribute a further $45 million to the year-to-year increase.

18. Oil costs are forecast to increase by $11 million in 1980. An increase in oil-fuelled generation of 110 GW·h in 1980 results in a $3 million increase. Rising unit consumption costs contribute an additional $7 million and increased underlifting costs account for $1 million. Underlifting is a trade term used in conjunction with oil supply arrangements where deliveries from a supplier are reduced

Fuel component of revenue requirement **Chart 5B5**



16. In 1980, the cost of fuels, as shown in table 5B4 is expected to be $761 million. This amount includes $150 million associated with the generation of export secondary energy. The cost of fuel in 1980 is $90 million greater than in 1979, an increase of 13%. This increase is due to increases in the volume of fuel consumed and higher unit consumption costs. The volume increase is associated with additional generation required to meet the increase in electrical demand. The higher unit consumption costs are associated with increases in the delivered prices of fuels which are reflected first in inventories and subsequently in bulk power costs.

17. The "coal" category in table 5B4 includes the consumption costs for coal, lignite, ignition oil, and combustion turbine oil. Generation from these sources is forecast to increase in 1980 by 2709 GW·h resulting in an additional cost of $44 million. Rising unit consumption costs primarily due to the addition of significant volumes of higher cost Western Canadian coal

from contracted quantities at the pruchaser's request.

19. Gas-fired generation is forecast to decrease by 634 GW·h in 1980. This decrease in generation produces a $16 million reduction in gas costs compared to 1979. Higher unit costs partially offset this reduction by $3 million.

20. Planned low levels of electricity generation from oil-fired and gas-fired stations result in correspondingly increased levels of production from coal-fired stations. The revenue requirement effect of the shift in generation mix is to minimize overall fuelling costs, despite oil underlifting costs, because of the substantially lower unit cost of coal as compared with oil and gas.

21. Energy from in-service nuclear units at Pickering NGS and Bruce NGS is forecast to increase by 256 GW·h in 1980. This

additional generation results in a $.5 million increase in the cost of nuclear fuel consumed. Higher unit consumption costs contribute a further $1.5 million to the year-to-year change.

FUEL COST TRENDS

22. Table 5B6 shows the quantities of fuel delivered and the quantities and costs of fuel consumed in 1978 and forecast to be delivered and consumed in the years 1979, 1980 and 1981 together with year-end inventories. Only the requirement for generation which is related to generation from in-service units, has a direct effect on the revenue requirement for fuels.

24. The increase in the average unit cost of fossil fuel consumed in 1980 is due mainly to general fuel price escalation and a higher proportion of more expensive Western Canadian bituminous coal in the fuel mix. This is partly mitigated by a projected improvement in the U.S./Canadian exchange rates in 1980, which affects U.S. coal cost.

25. The procurement of supplemental quantities of uranium concentrate at higher unit costs than for previously contracted base quantities is mainly responsible for the substantial increase in 1979 unit consumption costs for nuclear fuel, as shown in table 5B6. With the advent in 1980 of concentrate deliveries under additional long-term contracts, the resultant decrease in the cost of delivered fuel moderates the upward pressure on unit-consumption costs.

Fuel deliveries, consumption and year-end inventories — **Table 5B6**

	Actual	Forecast		
	1978	1979	1980	1981
FOSSIL FUELS (GJx10^6)				
Total deliveries	**293**	336	382	344
Less				
Requirement for commissioning and Bruce steam plant	**21**	3	2	2
Requirement for generation	**309**	356	377	335
Inventory	**213**	190	193	200
Consumption cost (¢/GJ)	**143**	170	183	199
Revenue requirement (M$)	**443**	604	691	666
NUCLEAR FUELS (MgU)				
Total deliveries	**643**	929	667	1050
Less				
Requirement for commissioning, steam for heavy water plants and capitalized first charge	**93**	51	111	138
Requirement for generation	**595**	565	555	639
Inventory	**326**	639	640	913
Consumption cost ($/kgU)	**81**	112	117	117
Revenue requirement (M$)	**48**	63	65	75

23. The increase in nuclear fuel inventories in 1979 is to raise inventory levels by an additional four month's requirement. Inventory levels remain relatively stable until 1981 when increased requirements lead to a forecast increase in nuclear fuel inventory.

26. Table 5B7, which complements table 5B6, shows the projected total delivered cost of fuels to be supplied to meet total requirements in the forecast period 1979-1981. The large annual increase in the total delivered costs of fuel purchases in 1979 as compared to 1978 is due to the

increase in deliveries of relatively more expensive low-sulphur western Canadian bituminous coal and to the higher cost supplemental nuclear fuel deliveries. The increases in total delivered costs in succeeding years are reduced as nuclear fuel supplies satisfy the major part of the growth in demand with a concommitant reduction in the relative proportion of fossil fuel deliveries.

Delivered costs of fuel purchases 1978-1981 — **Table 5B7**

$ millions

Year	Total Cost	Annual Increase
1978	541	—
1979	715	174
1980	780	65
1981	812	32

* * * * *

COMMISSIONING

Commissioning costs — **Table 5B8**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**22**	4	4	15
Change from previous year				
Fossil commissioning charges	**16**	(18)	2	(1)
Nuclear commissioning charges	**(46)**	—	(2)	12
	(30)	(18)	0	11

COMMISSIONING COSTS

27. Fossil commissioning costs increase by $2 million in 1980 resulting from a forecast increase of 130 GW·h in fossil commissioning energy. Nuclear commissioning energy is forecast to decrease by 145 GW·h in 1980. This decrease in nuclear commissioning energy accounts for a $2 million decrease in revenue requirement.

28. The value of energy supplied to the power system by a generating unit being commissioned is offset against the capital costs of the unit being commissioned. This value is computed on the basis of a rate ($/MW·h) established for each year of the forecast.

29. Commissioning rates represent the average cost of in-service generation which would be displaced by commissioning generation.

30. The rates shown in table 5B9 represent weighted averages based on the distribution of commissioning energy in the corresponding year. The calculation reflects the corporate policy that the cost of current operations is neither increased nor decreased by commissioning activity.

31. Commissioning charges for the period under review are shown in table 5B9.

Commissioning values				Table 5B9
	Actual	Forecast		
	1978	1979	1980	1981
Commissioning rate ($/MW.h)	**12.5*/13.2****	15.0	15.5	15.9
Nuclear commissioning energy (GW.h)	**347**	296	151	878
Fossil commissioning energy (GW.h)	**1,348**	—	130	70
Nuclear commissioning charges (M$)	**4**	4	2	14
Fossil commissioning charges (M$)	**18**	—	2	1
Total commissioning charges (M$)	**22**	4	4	15

*Weighted average nuclear-commissioning rate.
**Weighted average fossil-commissioning rate.

* * * * *

POWER PURCHASES

Power purchases				Table 5B10
$ millions				
	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**98**	84	104	93
Change from previous year				
Douglas Point	**2**	3	14	—
Contract/economy	**20**	(17)	6	(11)
	22	(14)	20	(11)

DOUGLAS POINT PURCHASES

32. The forecast of power purchases from Douglas Point in 1980 is increased by $12 million over 1979 because of the purchase of an additional 643 GW·h of energy. Higher unit costs contribute a further $2 million to the revenue requirement.

CONTRACT/ECONOMY PURCHASES

33. Contract purchases increase by 104 GW·h in 1980 due to increased deliveries from Manitoba Hydro under the Capacity Sale Agreement. Contract purchases from Hydro Quebec under the Energy Contract remain unchanged from the 1979 level of 2500 GW·h.

34. The level of economy purchases is essentially unchanged in 1980 from 1979. A small increase in economy purchases from Hydro Quebec is largely offset by an expected decrease in economy purchases from Ontario suppliers.

35. Higher prices for Energy Contract deliveries from Quebec and for economy purchases from all suppliers effectively account for the $6 million increase in forecast total contract and economy purchases.

36. The major assumptions used in the forecast of economy purchases are outlined in the following paragraphs. In this outline, 'C' means the supplier's cost of production and 'V' means the predicted incremental cost of fossil-fuelled energy on Ontario Hydro's system.

QUEBEC

37. Hydro Quebec is forecast to have surplus energy for sale to Ontario in excess of demands from the New Brunswick and New York markets and in excess of the energy reserved for Ontario in the Energy Contract. This surplus, 1550 GW·h in 1980, is priced at 0.80 V.

MANITOBA

38. Small amounts of economy energy, 250 GW·h, are forecast to be obtained from Manitoba. These are affected by proposed firm sales to Ontario throughout the period, which utilize most of the interconnection transmission capability. Economy energy is priced at (C+V)/2.

ONTARIO

39. Economy purchases will be available in small amounts, 107 GW·h, from miscellaneous Ontario sources, e.g. Canadian Niagara Power Company, Dow Chemical, Spruce Falls Power and Paper, etc. This economy energy is priced at (C+V)/2.

U.S.A.

40. No economy energy purchases are expected to be made from U.S. sources in 1980 and 1981 because running costs in the U.S.A. are usually higher than those in Ontario. Small amounts may occasionally be bought if the opportunity arises, but the probability of such purchases is too low to warrant including them in the forecast.

41. The forecast of contract and economy power purchases is detailed in table 5B11.

Power purchases – external resources* **Table 5B11**

	Actual		Forecast					
	1978		1979		1980		1981	
	GW.h	M$	GW.h	M$	GW.h	M$	GW.h	M$
Contract purchases								
Manitoba	**866**	**10.9**	1126	16.4	1230	18.0	1021	14.9
Quebec	**2750**	**34.6**	2500	32.3	2500	34.5	2250	32.2
Ontario	**42**	**0.9**	44	1.1	47	1.2	49	1.3
	3658	**46.4**	3670	49.8	3777	53.7	3320	48.4
Economy purchases								
Manitoba	**389**	**3.8**	250	2.6	250	2.8	350	4.1
Quebec	**4933**	**35.0**	1400	18.2	1550	21.4	950	13.6
Ontario	**408**	**4.4**	215	2.5	107	1.4	107	1.4
U.S.A.	**6**	**0.4**	—	—	—	—	—	—
	5736	**43.6**	1865	23.3	1907	25.6	1407	19.1
Total purchases	**9394**	**90.0**	5535	73.1	5684	79.3	4727	67.5
Other receipts	**1179**	**1.0**	1056	0.9	906	1.1	906	1.1
Total external resources	**10573**	**91.0**	6591	74.0	6590	80.4	5633	68.6

*Excludes Douglas Point

* * * * *

NUCLEAR PAYBACK

Nuclear payback — **Table 5B12**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**47**	52	64	65
Change from previous year	**(3)**	5	12	1

42. In table 5B13 the total net saving which relates the performance of Pickering Units 1 and 2 with two units at Lambton GS is shown along with the Ontario Hydro share of that saving. These calculations are in accordance with the three party financing agreement under which Pickering Units 1 and 2 were built.

Nuclear agreement/payback – Pickering GS — **Table 5B13**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Total net saving	**72**	79	98	100
Ontario Hydro share	**25**	27	34	35
Payment to AECL and Province of Ontario	**47**	52	64	65

43. The Pickering Agreement is between Ontario Hydro, the Canadian Government (through Atomic Energy of Canada Limited), and the Province of Ontario (through the Ministry of Energy). The three parties to the Agreement shared the capital cost of constructing the Pickering Nuclear Generating Station A - Units 1 and 2, and share proportionally in a "payback" which corresponds to the difference between the actual cost of power produced by Pickering Units 1 and 2, and the cost of producing that power had it been generated by Lambton (coal-fired) units 1 and 2.

44. During the hearing on 1979 bulk power rates, Ontario Hydro indicated that negotiations between Ontario Hydro and the other two parties were proceeding in which Ontario Hydro is seeking to convert the Agreement from the "payback" provision to some alternative provisions which would be more favourable to Ontario Hydro customers. At this time alternatives to the existing agreement are in the process of negotiation with progress being made on methodology and definition of the issues.

* * * * *

WATER RENTALS

Water rentals — **Table 5B14**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**18**	20	20	21
Change from previous year	**3**	2	—	1

45. Water Rental charges remain relatively constant throughout the forecast period.

C. Operation, Maintenance and Administration Costs (O.M.&A.) and Property Taxes

O.M.&A. — **Table 5C1**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**410**	503	509	562
Change from previous year	**84**	93	6	53

1. Bulk power O.M.&A. costs, as shown in table 5C1, comprise program costs and cost adjustments which are identified in table 5C2.

2. O.M.&A. program costs comprise the costs of

- operating and maintaining 37 electrical generation units at seven fossil-electric stations, 9 units at three nuclear-electric stations, 262 units at sixty-eight hydro-electric stations, and 42 combustion turbines
- operating and maintaining 218 transmission stations, and 40 thousand kilometers of transmission lines
- administering these facilities from head office, and seven regional offices
- operating, maintaining and administering distribution facilities comprising 792 distributing stations and 90 thousand kilometers of distribution lines only part of which affect bulk power costs

3. Table 5C2 summarizes O.M.&A. costs for the three-year period 1979 to 1981 and compares these budgeted costs to actual 1978 levels. The current estimate of O.M.&A. program costs is based on the initial 1979 - 1983 Work Program Budget, which was approved on January 15, 1979 and is in accordance with the recently announced organizational structure. Costs shown for the years 1980 and 1981 incorporate escalation provisions which have been developed in accordance with the Economic Outlook.

4. The current estimates of cost transfers and adjustments impacting on the bulk power O.M.&A. costs, as identified in table 5C2, are based on Financial Forecast 790420.

5. Table 5C3 summarizes the year to year changes in the bulk power O.M.&A. costs in the period to 1981. The bulk power O.M.&A. costs budgeted for 1980 are about $6 million greater than the level expected for 1979. This change is the net result of a $29 million constant dollar decrease in O.M.&A. programs and cost adjustments offset by a $35 million provision for escalation.

Increase in bulk power O.M.&A. costs — **Table 5C3**

$ millions

	Forecast		
	1979	1980	1981
Constant dollar increase (1979$)	66	(29)	12
Escalation	27	35	41
Total increase	93	6	53
% increase	23	1	10

1978-1981 bulk power operation, maintenance and administration costs — Table 5C2

$ millions escalated

	Actual	Forecast		
	1978	1979	1980	1981
Executive	**5.4**	6.6	7.6	8.6
Operations				
Design & construction	**19.9**	45.1	57.7	60.4
Distribution & marketing – bulk	**35.2**	34.4	34.9	37.5
– retail	**70.9**	67.0	69.6	75.7
Production & transmission	**311.2**	338.0	369.0	403.0
Supply and services	**41.5**	42.9	43.9	45.4
Total	**478.7**	527.4	575.1	622.0
Planning and Administration				
Corporate relations	**6.4**	8.3	7.8	8.3
Power system program	**22.6**	27.0	30.6	34.0
Resources	**33.8**	39.3	42.5	46.0
Total	**62.8**	74.6	80.9	88.3
Program Cost Adjustments				
Unallocated computer costs	—	1.9	4.4	7.0
Municipal utility restructuring	—	—	(3.7)	(4.5)
Other	—	1.7	1.2	1.9
Total	—	3.6	1.9	4.4
O.M.&A. program costs	**546.9**	612.2	665.5	723.3
Other Cost Adjustments				
Overheads capitalized & recovered	**(46.3)**	(32.2)	(34.9)	(37.6)
Indirect depreciation	**(28.7)**	(30.9)	(32.9)	(35.2)
Pole rentals	**(4.7)**	(3.4)	(3.7)	(4.0)
Retail O.M.&A.	**(73.0)**	(77.5)	(78.9)	(85.0)
Cobalt revenue	**(2.7)**	(3.0)	(3.0)	(3.7)
Other corporate expenditures	**18.8**	4.1	4.5	5.0
Revised escalation assumptions for 1979	—	(9.4)	—	—
Other	**.1**	43.4*	(7.7)	(.9)
Total	**(136.5)**	(108.9)	(156.6)	(161.4)
Bulk power O.M.&A. costs	**410.4**	503.3*	508.9	561.9

*Increase over the 1979 bulk power rate proposal is mainly due to write-off of costs associated with the decision to "stop and store" Wesleyville GS ($35 million), and to mothball Bruce heavy water plant D ($6 million).

6. The $29 million constant dollar decrease (1980 over 1979) in bulk power O.M.&A. costs is attributable to the factors shown in table 5C4.

Constant dollar change in bulk power O.M.&A. costs 1980 over 1979 — **Table 5C4**

1979 $ millions

• Write-off of costs in 1979 associated with the decision to "stop and store" Units 3 and 4 at Wesleyville GS	(35)*
• Write-off of mothballing costs in 1979 associated with the decision to essentially complete, mothball, and defer commissioning of Enricher 7 and Finisher 4 of the Bruce heavy water plant D	(6)*
• Non-recurring maintenance activities at various fossil generating stations in 1979	(6)*
• Deferral of preliminary engineering work on future generating stations as a result of reduced load growth and subsequent revisions in the Generation Expansion Program	(3)*
• Route and Site planning studies starting in 1980 on projects previously delayed due to increased public hearings	2
• Increased heavy water loss make-up costs as a result of increases in the unit mass cost in 1980, increases in volume loss as a result of equipment maturing, and the full-year impact of operating Unit 4 at Bruce NGS A	5
• Increased operation and maintenance costs at Bruce NGS A associated with security, low level radioactive waste storage facilities, replacement of standby operation exhaust ducts, training, and the full-year impact of operating Unit 4	4
• Operating and maintaining additional generating capacity at J.C. Keith GS and Thunder Bay GS	3
• All other factors	7
Total change in bulk O.M.&A. costs	(29)*

*Decrease

* * * * *

PROPERTY TAXES

Property taxes — **Table 5C5**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**13**	14	15	16
Change from previous year	—	1	1	1

7. Table 5C5 shows estimated property taxes (grants in lieu of taxes) for the three year period 1979 to 1981 and compares these budgeted costs to actual 1978 levels. Costs shown for the years 1980 and 1981 incorporate escalation provisions which have been developed in accordance with the Economic Outlook.

D. Fixed Charges

GENERAL

Fixed charges — **Table 5D1**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**746**	918	988	1116
Change from previous year	**181**	172	70	128

1. Capital Program costs comprise the costs of

- providing and modifying facilities for generation of electricity, bulk distribution of electricity and retail distribution of electricity
- providing and modifying facilities for heavy water production
- providing service and administration facilities and equipment
- operating and maintaining heavy water production facilities

2. Estimates of Capital Program costs are normally based on work program budgets. However, recent revisions to Ontario Hydro's load forecast and generation development program have outdated the initial 1979-1983 Work Program Budget. The revisions were approved by Ontario Hydro's Board of Directors on April 9, 1979.

3. Table 5D2 describes preliminary estimates of Capital Program costs for the three year period 1979-1981 and compares these estimated costs to actual 1978 levels. Costs shown for 1980 and 1981 incorporate escalation provisions which have been developed in accordance with the Economic Outlook, January 1979. These escalation provisions, along with constant dollar totals, are also presented in table 5D2.

4. As illustrated in chart 5D3, the Capital Program costs in the period 1978 to 1987 are now estimated to be substantially below the levels planned for the same period

Capital program costs—1978-1981 — **Table 5D2**

$ millions, escalated

	Actual	Forecast		
	1978	1979	1980	1981
Provide and modify electric generation facilities				
–Hydro-electric	**13**	18	21	26
–Fossil-electric	**218**	252	145	165
–Nuclear-electric	**586**	814	908	1,040
Provide and modify heavy water production facilities	**284**	216	40	5
Provide heavy water	**115**	201	338	355
Provide and modify facilities for the bulk transmission of electricity				
–stations	**131**	188	152	174
–lines	**167**	106	87	132
Provide and modify facilities for the retail distribution of electricity	**60**	70	74	80
Provide service and administration facilities and equipment	**106**	50	42	43
Totals–in escalated dollars	**1,680**	1,915	1,807	2,020
Provisions for cost escalation		—	109	242
Totals in constant 1979 dollars		1,915	1,698	1,778

last year. The decreases are due in part to the following changes in the previously committed generation development program.

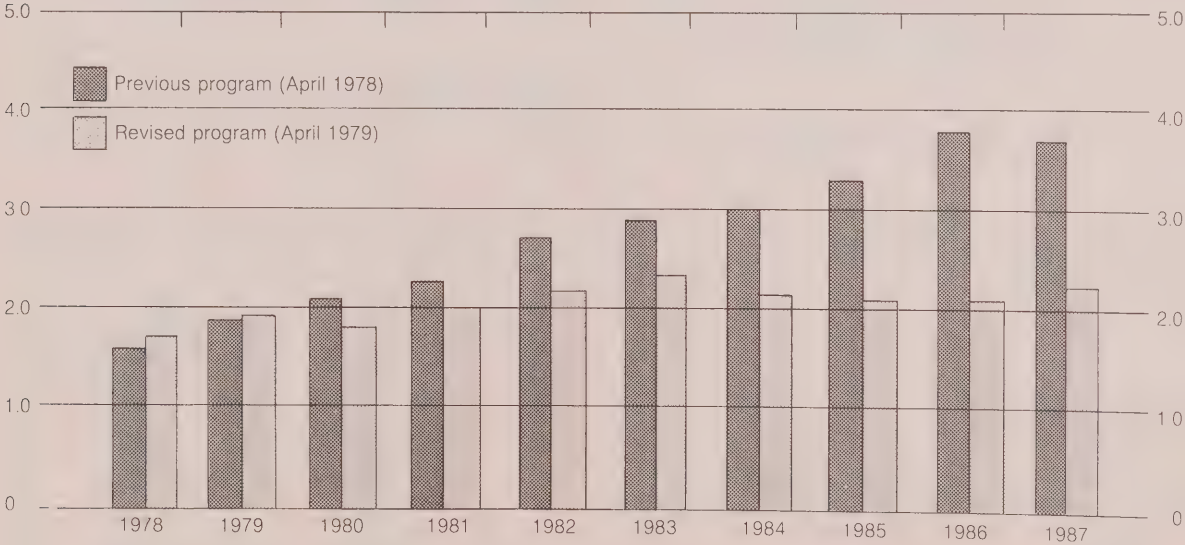
- stopping and storing two units at Wesleyville effective February 1979
- one year deferral of the in-service date for Atikokan Unit 1 and four year deferral of the in-service date for Atikokan Unit 2
- one year deferral of the in-service date for Bruce B Units 7 and 8
- one and one-half year deferral of the in-service date for Darlington Units 1 and 2 and two and one-half year deferral of Units 3 and 4

5. There are also substantial cost decreases due to the deferral of all planned but uncommitted generating facilities scheduled for in-service after Darlington GS. The transmission and transformation programs associated with both the committed and planned generation facilities have also been deferred, reducing the capital costs during the period.

6. The 1979 bulk power rate submission assumed a long-term deferral of Bruce heavy water plant D effective mid 1978. Enricher 8 was stopped and stored at the end of 1978. Enricher 7 and Finisher 4 will be mothballed upon completion and commissioning will be deferred until these facilities are required.

Comparison of annual capital program costs **Table 5D3**

$ billions, escalated



	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Previous Program	1.61	1.89	2.11	2.34	2.75	2.99	3.07	3.33	3.85	3.71
Revised Program	1.68	1.92	1.81	2.02	2.18	2.28	2.12	2.04	2.05	2.18

BORROWING REQUIREMENT

7. Cash requirements in the period under review, the major portion of which is represented by capital expenditures, are shown in table 5D4 along with internal financing estimates and the resulting borrowing requirements.

Gross borrowing requirement **Table 5D4**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Capital requirement				
Capital program costs—net	**1,652**	1,763	1,705	1,954
Other cash requirements—net	**362**	661	668	688
Liquidity change	**236**	(94)	(67)	7
	2,250	2,330	2,306	2,649
Less: internally generated funds	**433**	439	556	849
Gross borrowings	**1,817**	1,891	1,750	1,800

8. The following historical table, 5D5 has been prepared to show Ontario Hydro's gross borrowing in various markets in the period 1974 to 1978. The continuing importance of foreign capital is shown in the column "% Foreign".

CAPITAL AVAILABILITY

9. Estimates in table 5D6 represent Ontario Hydro's assessment of the total capital available to the Corporation in 1980 and 1981. No problems are anticipated in 1979. This assessment is based on Ontario Hydro's experience with recent issues in the various capital markets plus the ongoing advice the Corporation receives from its various financial advisors. It is also consistent with the Economics Division's current estimates of gross capital availability.

10. These estimates assume the continuance of normal market conditions. However, capital from particular markets could be reduced temporarily because of unanticipated economic or political developments. In such cases, it would be necessary for Ontario Hydro to make extensive use of markets that are more costly with shorter maturities, such as, the Swiss, German and Japanese capital

Borrowing by markets 1974-1978 **Table 5D5**

$ millions*

	Canadian Long & Intermediate	U.S.A. Public & Private	Other Foreign	Canadian Short Term (Net)	Total	% Foreign
1974	400	300	—	71	771	39
1975	450	775	339	(46)	1,518	73
1976	600	650	250	—	1,500	60
1977	750	500	125	(79)	1,296	48
1978	800	700	125	(29)	1,596	52
	3,000	2,925	839	(83)	6,681	56
	45%	44%	12%	(1)%	100%	

*U.S. $ assumed equal to Canadian $.

markets. Borrowing in these markets would incur the risk of additional costs arising from adverse foreign exchange movements.

Capital availability to Ontario Hydro gross new issues 1980-1981 — **Table 5D6**

$ millions – Canadian

	Canada		U.S.	Overseas	Total
	Short-Term*	Long-Term			
1980	—	950	825	150	1925
1981	100	1150	825	175	2250

*Less than one year maturity: net

11. This forecast of capital availability assumes that Ontario Hydro will continue to meet the following fundamental requirements.

- financial integrity remains unimpaired
- credit rating remains at the existing level
- the economic viability of the assets created with borrowed funds continues to be acceptable from the investor's point of view

12. Table 5D7 provides figures comparing borrowing requirements and capital availability for the years 1980 and 1981.

Borrowing requirement compared to capital available — **Table 5D7**

$ millions

Year	Borrowing requirement	Capital available	Estimated surplus funds
1980	1750	1925	175
1981	1800	2250	450

* * * * *

INTEREST

Interest — **Table 5D8**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**508**	628	668	752
Change from previous year	**135**	120	40	84

13. Interest comprises about two-thirds of Ontario Hydro's fixed charges forecast for 1980. In essence it consists of the cost of borrowed funds, reduced by income earned on investments and the amount of interest capitalized as plant under construction or as part of the cost of heavy water produced. The bulk power revenue requirement for interest is forecast as $668 million in 1980. Details of the components of interest are presented in table 5D9.

14. Foreign exchange losses related to maturing debt in 1978 totalled $66 million but were offset by gains on U.S. dollar deposits of $37 million for a net exchange loss of $29 million. In 1979 losses related to maturing debt are forecast to be $43 million with $26 million attributable to the refinancing of a Deutsche Mark serial bond issue. Foreign exchange losses are forecast to be $21 million in 1980 and $22 million in 1981.

15. Table 5D10 provides an analysis of change in the bulk power interest from year to year. In 1980 interest expense is forecast to increase bv $40 million or 6% from the 1979 level of $628 million. This is a relatively small increase and is a direct reflection of the reduced amount of operating facilities added to the power system and a reduction in foreign exchange losses on maturing debt.

16. In 1980 Thunder Bay GS Unit 2 is the only new generation added to the system and this addition is late in the year. As a result the increase in interest is less than

Interest expense

Table 5D9

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Interest expense				
On bonds and long-term notes	**876**	1011	1150	1285
On short-term notes	**3**	2	2	2
On heavy water plant purchase and head office lease agreement	**21**	20	19	18
Gross interest charges	**900**	1033	1171	1305
Reduced by:				
Interest capitalized				
On fixed assets under construction	**273**	270	290	324
On heavy water production facilities	**26**	51	107	106
Interest earned on investments	**74**	72	51	50
Net exchange gain (loss) on redemption and translation of foreign assets and liabilities	**(29)**	(43)	(21)	(22)
Interest charged on advance payments for fuel supplies	**5**	14	26	36
Miscellaneous interest	**2**	(2)	6	11
	351	362	459	505
Total interest charged to operations	**549**	671	712	800
Less interest allocated to the retail system	**41**	43	44	48
Bulk power interest	**508**	628	668	752

in 1979 when Bruce A NGS Unit 4 was placed in service in February and also less than in 1981 when Thunder Bay GS Unit 1 and Pickering B NGS Unit 5 are expected to be placed in service in April.

17. Significant investments are forecast for the development of fuel supplies. As deliveries commence, the interest associated with these investments is no longer capitalized but charged to the cost of power through the cost of fuel. Uranium deliveries from Denison Mines are expected to commence in 1980 and from Preston Mines in 1983. Small amounts of uranium relative to the size of the contract will be received from Denison in the early years and because of the size of the contract, the impact of stopping all interest capitalization and charging current operations would result in an inappropriate matching of costs and benefits. As a result some capitalization of interest will continue and charges to current operations will increase as deliveries are increased.

18. Deferral of capital projects for more than one year results in interest being charged directly to current operations. Interest cost is increased by $26 million in 1979 and a further $25 million in 1980 because of the deferral of Wesleyville GS and Bruce heavy water plant D.

Bulk power interest expense increases			Table 5D10
$ millions change from previous year			
	Forecast		
	1979	1980	1981
Changes in interest expense associated with:			
Facilities placed in service	102	59	125
Resource development projects	2	3	4
Increased inventories	8	7	7
Net exchange on redemption and translation of foreign assets and liabilities	14	(22)	1
Internally-generated funds	(38)	(41)	(61)
Construction deferral of Wesleyville and Bruce heavy water plant D	26	25	11
Other	6	9	(3)
	120	40	84
% increase	24	6	13

* * * * *

DEPRECIATION

Depreciation				Table 5D11
$ millions				
	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**238**	290	320	364
Change from previous year	**46**	52	30	44

19. Ontario Hydro's depreciation policy for major fixed assets is to allocate the service cost of major fixed assets to the cost of power in relation to the contributions made by these assets to the provision of power to customers, where service cost is considered to represent original cost plus all other significant capital costs and recoveries that are related to an asset's service use. Under this policy all major fixed assets are depreciated on the straight-line remaining-life basis. At present, other capital costs and recoveries have not been determined to be of such significance to warrant inclusion in the depreciation base. Any such costs that do materialize and are not covered by accumulated depreciation, are charged to depreciation expense in the year incurred.

20. Depreciation rates are established for categories of assets based on their estimated service lives. These estimated service lives are subject to periodic review by the Depreciation Review Committee. The service lives of major fixed assets are

- Generation facilities:
  - Hydro-electric 50-100 years
  - Fossil-electric 30 years
  - Nuclear-electric 30 years
- Transmission and distribution facilities 25-50 years
- Administration and service facilities 5-60 years
- Heavy water production facilities 20 years
- Heavy water 52 years

21. The policy for the classification of expenditures as current operations or capital defines capital expenditures as those which relate to the initial design and construction of specific assets or to the subsequent improvements or additions to existing facilities. As a result, certain engineering expenditures related to the overall planning and development of the power system are charged to current operations. Expenditures on preliminary engineering studies of this nature which had been capitalized up to December 31, 1978, are being amortized on a straight-line basis at 9% per annum.

22. Effective January 1, 1979, Ontario Hydro's accounting policy for deferred projects was extended to allow for the amortization of capital projects deferred more than one year. Deferred projects are amortized on a straight-line remaining-life basis with the amortization rates being subject to periodic review by the

Depreciation Review Committee. The initial amortization rates are set at the depreciation rates for similar in-service assets.

23. The bulk power revenue requirement for depreciation expense is forecast as $320 million in 1980. Details of the depreciation expense by class of asset are presented in table 5D12.

Depreciation by asset class **Table 5D12**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Hydraulic generation	**21**	31	31	31
Fossil generation	**73**	83*	88*	98*
Nuclear generation	**66**	84*	98*	121*
Total	**160**	198	217	250
Transmission				
—stations	**27**	30	35	40
—lines	**17**	23	27	30
Miscellaneous	**34**	39	41	44
Total	**238**	290	320	364

*Includes amortization of deferred projects.

24. Table 5D13 provides an analysis of the change in depreciation expense from year to year. In 1980 this change represents an increase of $30 million over the 1979 level.

25. Additions to facilities in service account for most of the increase in depreciation over the forecast period. In 1980 they include the conversion costs of J.C. Keith to low-sulphur coal scheduled for June, and one unit at Thunder Bay scheduled for October.

26. Capital expended for the deferred projects of Wesleyville GS and Bruce heavy water plant D is being amortized on a straight-line remaining-life basis. Amortization is assumed to begin at the date of deferral and will be based on the depreciation rate for the appropriate asset class.

Depreciation expense increases **Table 5D13**

$ millions change from previous year

	Forecast		
	1979	1980	1981
Depreciation of facilities placed in service	36	18	38
Amortization of capital costs of deferred projects	11	12	6
Other	5	—	—
	52	30	44
% increase	22	10	14

E. Net Income

Net income				Table 5E1
$ millions				
	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**160**	112	192	430
Change from previous year				
Debt retirement	**15**	21	20	18
Stabilization of rates	**(38)**	(70)	64	220
Deficit recovery	**3**	1	(4)	—
	(20)	(48)	80	238

1. Ontario Hydro's revenue requirement includes a net income component. Determination of the appropriate level of net income is based on the position that the financial soundness of the Corporation should be maintained and that certain indicators of financial performance should be used as guides in meeting this objective. This position was adopted in 1973 and restated in 1975 when interest coverage and the debt ratio were recommended as primary indicators. It was determined that a debt ratio in the range of .80 - .82 and an interest coverage of 1.35 would provide for a sound financial position.

2. Charts 5E2 and 5E3 show that Hydro has not met its debt ratio or interest coverage targets in recent years.

- In 1976, this was mainly the result of two factors: the decision of the Hydro Board to accept a recommendation by the Select Committee of the Legislature to limit the increase in that year; and secondly, net income was substantially below expectations because of adverse conditions affectng the provincial economy.
- Hydro's income in 1977 and 1978 was reduced as a result of conforming to the spirit and intent of the Anti-Inflation Program in accordance with Provincial Government policy.
- For 1979 rates, the Hydro Board recognized the need for continued restraint in the post-control period and decided to hold the level of net income to be included in rates to an amount compatible with that permitted under the Anti-Inflation Program. The cost associated with deferring Wesleyville GS and the Bruce heavy water plant D along with lower than forecast load, are expected to result in slippage in the debt ratio for 1979 from the forecast level at which the 1979 rates were set.

3. In arriving at its rate proposal for 1980, the Hydro Board weighed its concern regarding financial soundness against the impact on customers of moving to an interest coverage of 1.35 in one year when the effective rate increase is already substantial. It was decided that the 1980 increase should be held at an absolute minimum but that the debt ratio should not be allowed to fall further than the level forecast for the end of 1979.

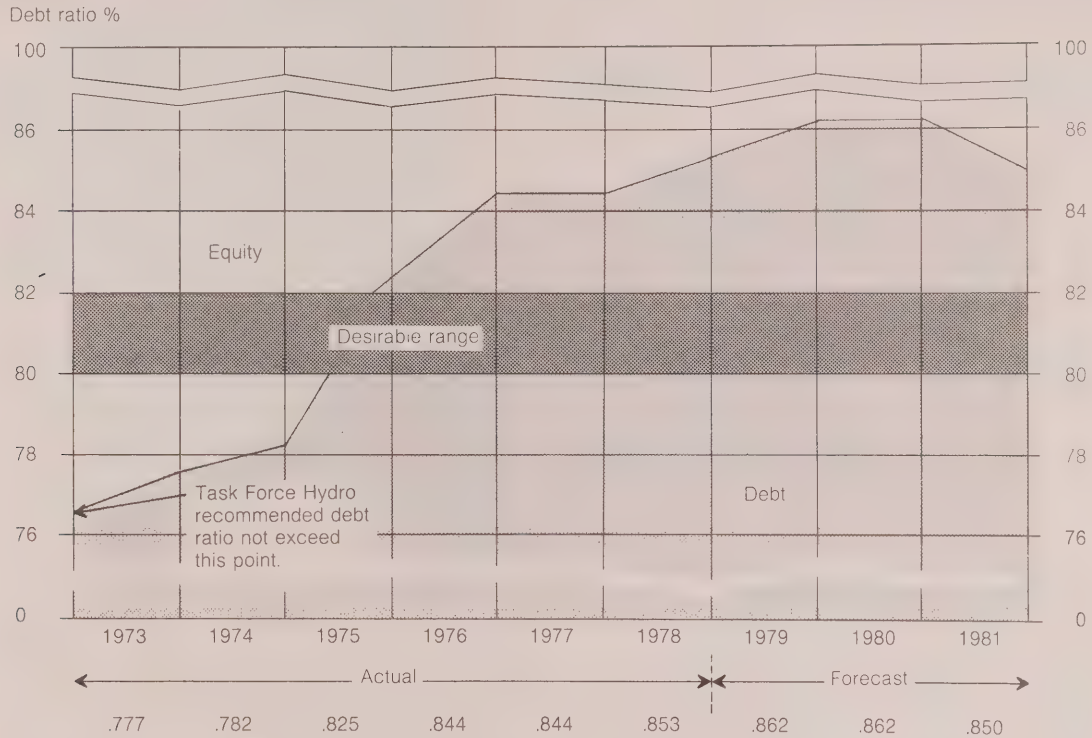
4. For 1980, this will require bulk power net income of $192 million and will result in a debt ratio of .862 and an interest coverage of 1.18.

5. Revisions to the system expansion program will again have a moderating effect on borrowing requirements.

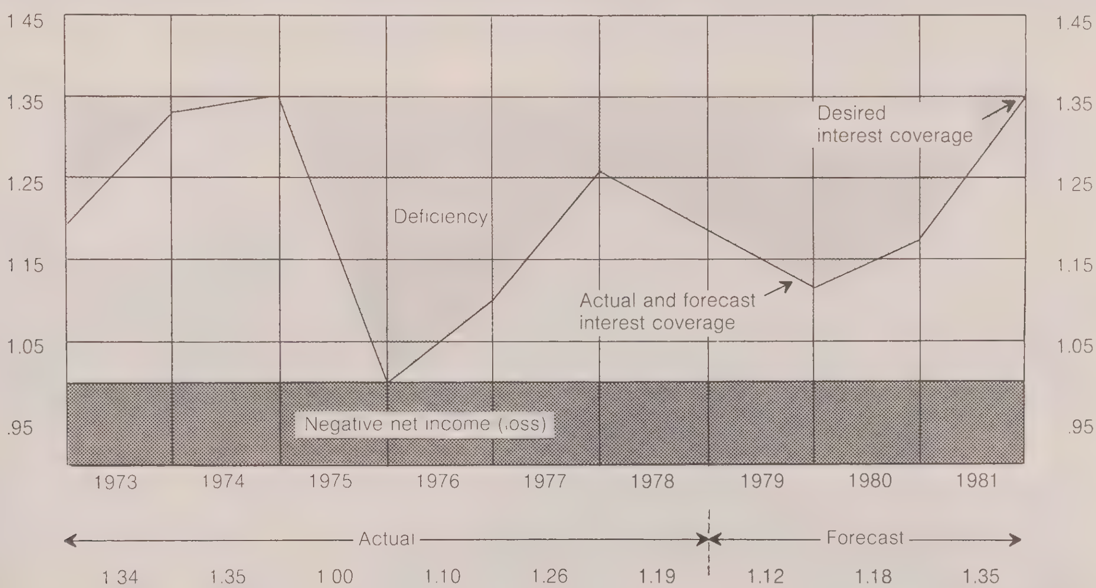
6. It has been assumed that Hydro will earn sufficient net income to provide an interest coverage of 1.35 in the years after 1980 in the financial forecast period.

7. Current levels of net income are not proportionately high from an historical perspective. Trends illustrating the increased reliance Hydro has had to place on borrowed funds relative to those generated internally are shown in charts 5E4 and 5E5. Another perspective on Hydro's cash flow is provided by cash flow as a percent of gross interest cost as shown in chart 5E6.

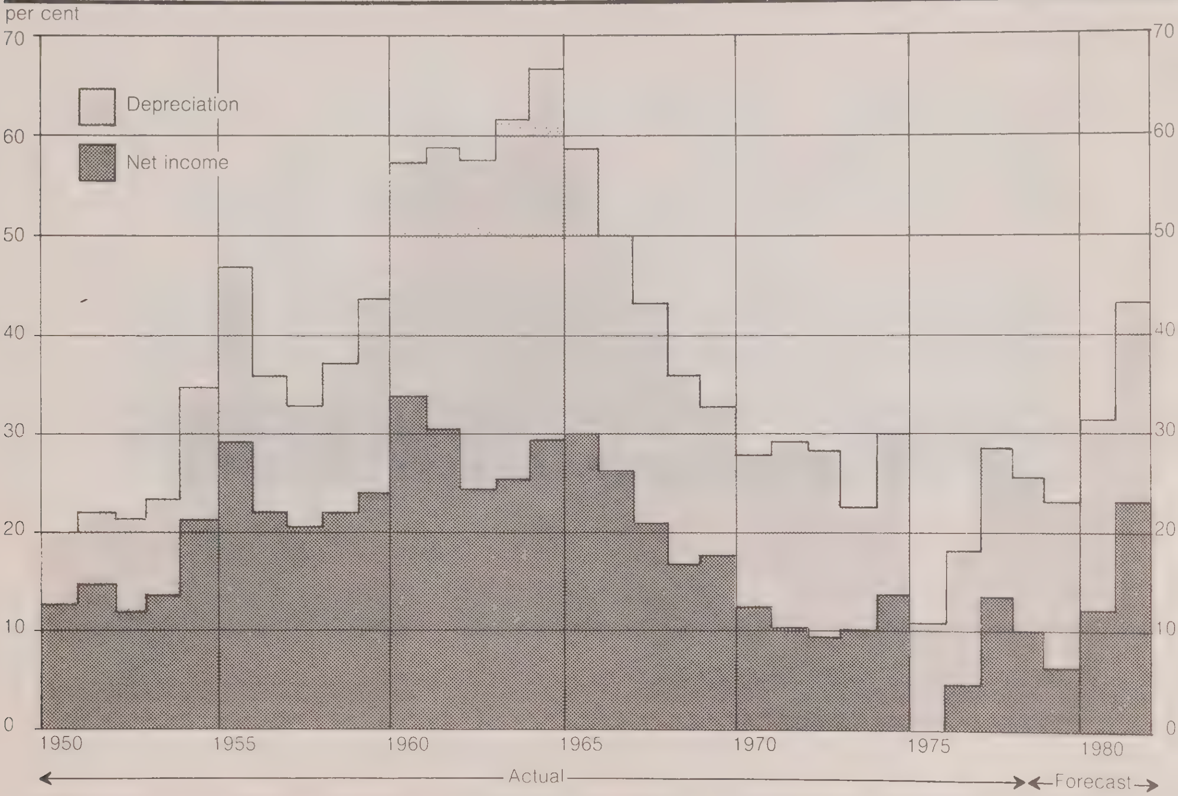
Debt ratio **Chart 5E2**



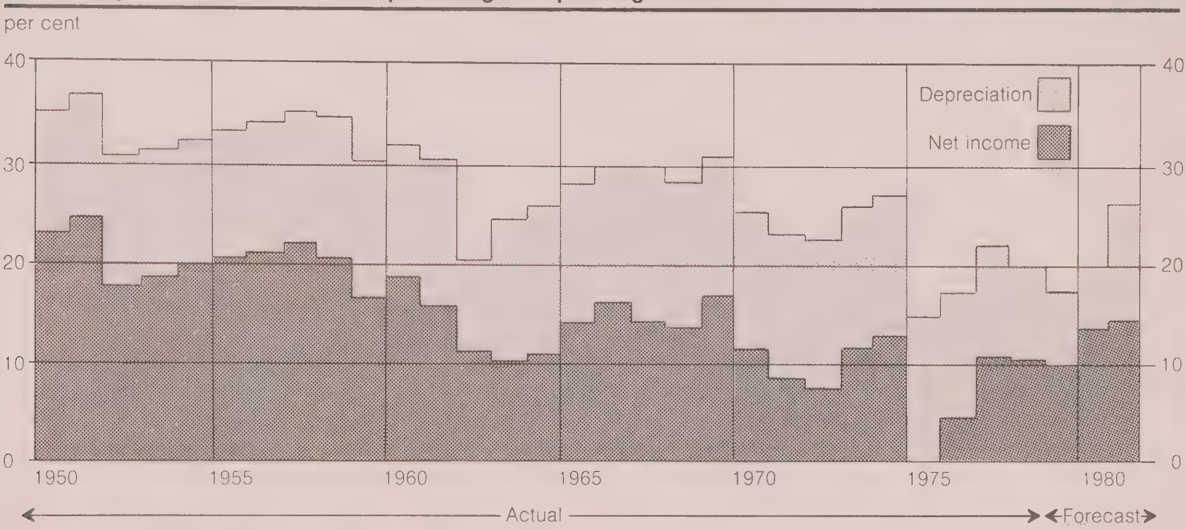
Interest coverage **Chart 5E3**



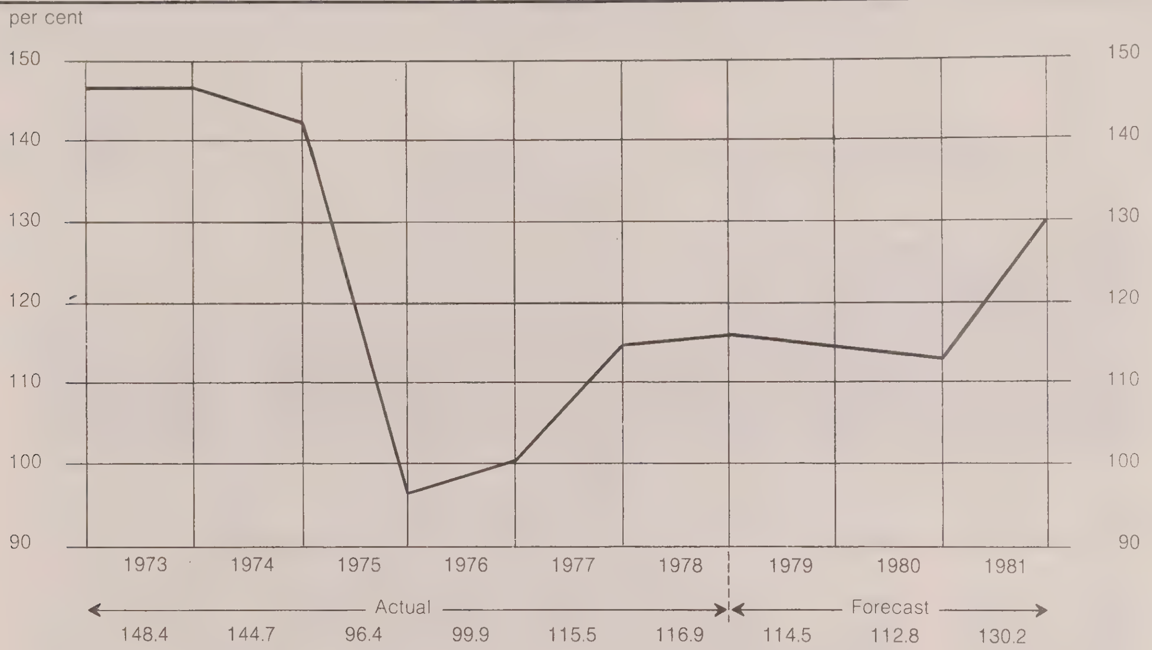
Internally generated cash flow as a percentage of capital expenditure **Chart 5E4**



Internally generated cash flow as a percentage of operating revenue — Chart 5E5



Cash flow as a per cent of gross interest cost **Chart 5E6**



F. Secondary Revenue

Secondary revenue — **Table 5F1**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**(289)**	(294)	(291)	(202)
Change from previous year	**(79)**	(5)	3	89

1. Ontario Hydro's secondary revenue is derived almost entirely from export sales of surplus interruptible power and energy.

2. Ontario Hydro's policy on the export of surplus interruptible power is as follows.

- to provide emergency assistance to the maximum extent deemed consistent with the safe and proper operation of its own system, and with its prior obligations to other Canadian systems

- to take advantage of opportunities for profitable sales at times other than emergencies in such quantities as deemed desirable having due regard for conditions on the Ontario Hydro system

- to obtain a fair and economic return for the services provided, and to maximize the longer-term economic gain to Ontario, taking into account all applicable costs incurred in Canada and having due regard to the possibility that Ontario Hydro may need to purchase in future under the same conditions

- to adhere to the Corporation's policies on the conservation of energy and to any applicable governmental rules and regulations, including those relating to the use of resources, environmental restrictions, priority of supply and quantities that may be exported

3. Estimates of secondary revenue are based upon consideration of

- the availability of power and energy surplus to Ontario's need

- the capability of the transmission system to deliver

- the availability of a market at an appropriate price

4. The reduced load forecast has the effect of increasing the expected availability of generation to supply the secondary market. The limiting factor on sales has usually been demand from the secondary market, but transmission-system limitations are now becoming more significant.

5. Michigan, currently the largest market with relatively low reserves and a considerable amount of oil-fired generation, will continue to rely on imported power from time to time, and Ontario should fill a substantial portion of these requirements.

6. The New York market remains difficult to predict. It was expected that sales to New York would decline with the commissioning of the New York line, however the level of sales is exceeding that of last year, principally because of two factors. First, the Iranian oil situation has resulted in a dramatic increase in oil prices along the eastern seaboard of the U.S.A., which provides increased incentives to make transactions; and second, the U.S. government is applying increased pressure to minimize oil consumption.

7. Prices for secondary energy are assumed to escalate with the price of fuels (coal and oil). However, these prices are subject to competitive forces; they may escalate faster than fuels if there is no competition from other suppliers, or at a slower rate if the competition is severe.

8. The forecast quantities, expected average price per kilowatt-hour, the gross revenue, and the accounting cost of export sales used in computing the 1980 revenue requirement are presented in table 5F2. Various non-export sales and transfers make up the difference between revenue shown in tables 5F1 and 5F2 for the year 1978.

1979 forecast of secondary sales to U.S.A. **Table 5F2**

	Actual	Forecast		
	1978	1979	1980	1981
Energy (GW.h)	10,364	10,000	9,000	6,000
Average price (m$/kW.h)	27.4	29.4	32.2	33.6
Gross revenue (M$)	284.2	293.8	290.2	201.8
Accounting costs (M$)	141.6	159.2	150.0	103.6

9. Accounting costs are projected on an inventory-consumption basis. These costs are indicative of the impact on Ontario Hydro's revenue requirement in the year of the sale.

10. The volume of secondary sales is highly erratic and unpredictable because it is influenced by

- randomly occurring outages of equipment on the interconnected power system
- the effect of competition, particularly in the Michigan market, where neighbouring utilities to the south experience lower fuel costs
- uncertainty of cost and availability of fuel for U.S. oil-fired plants, particularly along the eastern seaboard
- uncertain primary load growth in both source and market areas
- major fluctuations in the exchange rate

G. Internal Sales

Internal sales **Table 5G1**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**(12)**	(15)	(23)	(27)
Change from previous year	**(3)**	(3)	(8)	(4)

1. Internal sales represent the use of electricity for generating station construction and for the operation of the Bruce heavy water plants. This cost-transfer procedure ensures that the capitalized values of the resulting assets include an appropriate share of the current energy production costs.

2. Internal sales are priced at the rate charged to municipal utilities for equivalent conditions of supply minus the provision in the rate for net income.

3. Table 5G2 details the forecast demand and energy consumption, the rates applied, and total transfer value.

Internal sales details **Table 5G2**

	Actual	Forecast		
	1978	1979	1980	1981
Demand (MW)				
BHWP	**87**	103	148	150
Construction power	**10**	9	6	9
	97	112	154	159
Energy (GW.h)				
BHWP	**647**	749	1075	1091
Construction power	**52**	54	37	49
	699	803	1112	1140
Rates				
Demand ($/kW)	**58.28**	63.8	69.7	74.6
Energy (m$/kW.h)	**9.3**	10.2	11.2	13.2
Transfer value (M$)				
BHWP	**11.0**	14.2	22.5	25.5
Construction power	**1.0**	1.2	0.8	1.3
	12.0	15.4	23.3	26.8

H. Bruce Steam Transfer

Bruce steam transfer — **Table 5H1**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenue requirement	**(8)**	(19)	(28)	(27)
Change from previous year	**(8)**	(11)	(9)	1

1. Steam is produced at the Bruce NGS A for the production of both electricity and heavy water and the nuclear-fuelling costs are shared proportionately by both these products.

2. In circumstances where steam that could be used to produce electricity is transferred to make heavy water, the additional costs incurred by the bulk electricity system are charged to heavy water production and a corresponding credit is made to the cost of power. This credit is called the "Bruce Steam Transfer Credit" and is determined by converting the steam transfer to its electrical equivalent and applying a rate equal to the difference between the average replacement cost of energy on the bulk electricity system and the nuclear-fuelling cost.

3. The Bruce heavy water plants are expected to require steam according to table 5H2. The "Other" column, under the heading "not affecting bulk electricity system" in table 5H2, designates steam transferred to the Bruce heavy water plant that could not have been used for the supply of electricity to the bulk electricity system because of such constraints as outages to the turbine-generator sets and transmission line limitations. Of these, the latter is expected to be the predominant factor.

4. The estimated credits to the cost of power for transfers of steam to heavy water production involving curtailment in electricity production at Bruce NGS A are shown in table 5H3.

Bruce heavy water plant steam requirement — **Table 5H2**

GW • h

				from Bruce NGS		
				not affecting bulk electricity system		
	Total steam demand (electrical equivalent)	from Douglas Point	from Bruce steam plant	Stretch*	Other	affecting bulk electricity system
1979	2776	136	204	—	882	1554
1980	3669	68	98	—	1241	2262
1981	4337	60	98	2004	88	2087

*Stretch steam is defined as that which is in excess of turbine generator design capacity

Bruce steam transfer credit **Table 5H3**

	Forecast		
	1979	1980	1981
Steam transferred to BHWP which affects bulk electricity system (GW•h)	1554	2262	2087
System average replacement value of energy ($/MW•h)	14.5	14.6	15.1
Bruce in-service fuelling costs ($/MW•h)	2.0	2.1	2.1
Difference ($/MW•h)	12.5	12.5	13.0
Bruce steam transfer credit (M$)	(19)	(28)	(27)

Chapter 6
PROPOSED RATES

A. General

1. Bulk power system costs are allocated through wholesale rates to the municipal utilities and to the Power District. The Power District is the wholesale entity representing Ontario Hydro's retail customers including the large direct customers.

2. Wholesale rates are established so that the total estimated revenue will approximate the estimated bulk power allocated costs. The rates consist of charges applicable to the customers' monthly peak demand and energy consumption and may include miscellaneous charges and credits as well.

3. For 1980, the bulk power system common costs have been allocated to demand and energy components by allocating energy at 1.12 cents per kilowatt-hour, the remaining amount being allocated to demand. The energy allocation rate of 1.12 cents per kilowatt-hour has been determined by increasing the 1979 energy allocation rate of 1.02 cents per kilowatt-hour by the same percentage as the overall increase proposed for the 1980 bulk power rates. This maintains the existing relationship between demand and energy charges and provides a nearly uniform impact on all municipal utilities and the Power District. The energy rate for 1979 was determined in the same manner.

4. Pending decisions with respect to recommendations of the Electricity Costing and Pricing Study, which is the subject of a separate hearing before the Ontario Energy Board, no relative changes in the demand/energy allocation have been made.

5. The allocation of forecast costs for 1980 to the municipal utilities and the Power District is shown in table 6A1 on both a total cost and a unit cost basis.

6. The allocation of the Power District share of bulk power costs for 1980 to the Direct Customers and Rural Customers is shown in table 6A2 on a total cost basis.

Allocation of total bulk power costs **Table 6A1**

	1980 Forecast Costs			
	Municipalities		Power District	
Functional costs	Total (M$)	Unit ($/kW)	Total (M$)	Unit ($/kW)
Total common demand costs	812.0	80.31	350.9	81.45
1st stage transformation	62.8	6.48	17.2	6.48
Switchgear allowance	(2.0)	(.94)	—	—
2nd stage transformation	1.0	4.58	6.1	4.58
Meters	1.0	.10	.3	.10
Specific facilities (% of capital)	.7	17.29	—	—
Sundry	—	n/a	(5.2)	n/a
Energy	715.9	1.12 (¢/kW.h)	354.9	1.12 (¢/kW.h)
Total	1,591.4		724.2	
Other data				
Group peak load (MW)	10,110		4,308	
Energy (GW.h)	63,913		31,690	

Allocation of power district share of bulk power costs

Table 6A2

$ millions

	1980 Forecast Costs		
	Direct Customers	Rural Customers	Power District
Functional costs			
Total common demand costs	171.1	179.8	350.9
1st stage transformation	3.3	13.9	17.2
2nd stage transformation	.1	6.0	6.1
Meters	.2	.1	.3
Sundry	(5.1)	(.1)	(5.2)
Energy	194.1	160.8	354.9
Total	363.7	360.5	724.2
Other data			
Group peak load (MW)*	2,146	2,294	4,308
Energy (GW•h)	17,338	14,352	31,690

*The group peak load of the Power District reflects the coincident average monthly peaks of the Direct and Rural customers. The sum of the group peak loads of these two customer classes is greater than the Power District peak load.

Chapter 6
PROPOSED RATES

B. Rates

MUNICIPAL UTILITIES

1. The various cost functions and the proposed schedule of wholesale rates and other charges and credits for 1980 applicable to the municipal utilities, together with similar data for 1979, are set out in table 6B1.

3. The effect of the proposed increase in wholesale rates on the ultimate retail customers of the municipal electric utilities will vary. It does not follow that the retail rate adjustment need be of the same percentage nor coincide in effective date with the increase in wholesale rates. The financial position of some municipal utilities may permit them to defer temporarily an increase in their retail rates. On the other hand, the utilities are faced with escalating local operating costs which are also placing pressure on existing retail rate levels. The net effect on such levels will vary according to their local cost conditions.

Municipal utility rate schedule **Table 6B1**

	Supply Voltage					
	Over 50 kV		10 kV to 50 kV		Under 10 kV	
	1979	1980	1979	1980	1979	1980
Functional costs ($/kW)						
Common cost	74.17	80.31	74.17	80.31	74.17	80.31
Stage I transformation	—	—	4.60	6.48	4.60	6.48
Stage II transformation	—	—	—	—	4.66	4.58
Meters	.09	.10	.09	.10	—	—
Total	74.26	80.41	78.86	86.89	83.43	91.37
Monthly rates						
Monthly demand billing rate ($/kW)	6.19	6.70	6.57	7.24	6.95	7.61
Energy rate (¢/kW•h)	1.02	1.12	1.02	1.12	1.02	1.12
Other monthly charges and credits						
Specific facility charge (% of capital)	—	—	1.308	1.441	1.308	1.441
Ownership of low voltage switchgear credit ($/kW)	—	—	.06	.08	—	—
Standby charge ($/kW)	—	—	.93	1.07	—	—
Delayed billing factor						
applicable to monthly demand and consumption	1.003	1.003	1.003	1.003	1.003	1.003

2. Application of the proposed schedule of rates is estimated to increase revenue from the municipal utilities by 9.9% over the amount that would have been obtained at existing rates excluding any effect of anti-inflation rebate as applicable. The impact from utility to utility may vary slightly but all utilities are within a 9.0 to 10.2% range.

DIRECT CUSTOMERS

4. Direct customers, generally located outside municipal boundaries, are customers with power demands exceeding 5000 kW and

served directly under contracts with Ontario Hydro. Where direct customers are located within a municipality, they are supplied by Ontario Hydro with the agreement of the municipality. At the end of 1978, 101 direct customers were supplied by Ontario Hydro.

5. Under contracts existing at the end of 1972, rate adjustments for direct customers may be implemented on January 1st of any year and each customer must be advised of such an adjustment by registered mail at least 60 days preceeding the January 1 implementation date. All contracts negotiated since 1972 include the provision that Ontario Hydro may adjust the rates by notice given at least 60 days prior to the effective date of such a rate adjustment. However, the clause also includes the condition that there shall not be more than one rate change in a period of 12 consecutive months.

6. The categories of Direct Customer service are as follows:

- Main Service Classification

  Firm Power and associated special condition service

  - Interruptible "A"
  - Interruptible "B"
  - Scheduled "C"
  - Scheduled-Hour Class 1
  - Scheduled-Hour Class 2

- Auxiliary Service Classification

  - Furnace Loads (Firm, and/or Interruptible Power)
  - Excess Power
  - Standby Service and Standby Power
  - Supplementary Power
  - Short-Term Power

- Distributing Companies

7. The energy rate to direct customers has been increased to 1.21 cents per kilowatthour. It has been determined by increasing the current rate of 1.12 cents per kilowatthour by the same percentage as the overall increase proposed for the direct customers. This is the same principle as applied to the bulk power cost allocation and has the effect of minimizing change in the existing relationship between demand and energy. The energy rate for 1979 was determined in the same manner.

8. Table 6B2 sets out the proposed revisions to the standard rate schedule along with a comparison to existing rates.

Standard rates — **Table 6B2**

	Approved for 1979	Proposed for 1980
Demand rates (per kW of billing demand per month)		
Class of power		
230 kV		
– Firm	$4.74	$5.03
– Interruptible 'A'	3.89	4.08
– Interruptible 'B'	3.55	3.84
– Scheduled 'C'	3.32	3.60
– Scheduled-hour Class 1	1.43	1.75
Class 2	.87	1.07
– Excess	5.93	6.29
– Standby service	.74	.76
115 kV		
– Firm	4.87	5.16
– Interruptible 'A'	4.02	4.21
– Interruptible 'B'	3.68	3.97
– Scheduled 'C'	3.44	3.73
– Scheduled-hour Class 1	1.56	1.91
Class 2	.95	1.17
– Excess	6.09	6.45
– Standby service	.74	.76
10 to 50 kV		
– Firm	5.17	5.60
– Interruptible 'A'	4.32	4.65
– Interruptible 'B'	3.98	4.41
– Scheduled 'C'	3.75	4.17
– Scheduled-hour Class 1	1.72	2.06
Class 2	1.05	1.26
– Excess	6.46	7.00
– Standby service	.90	.98
Under 10 kV		
– Firm	5.47	5.91
– Interruptible 'A'	4.62	4.96
– Interruptible 'B'	4.28	4.72
– Excess	6.84	7.39
Energy rate (per kW•h)	1.12¢	1.21¢

9. An updating of the calculation of the discounts, as outlined in the "Report on the Interim Study of Interruptible Power and

Scheduled Power" dated February 21, 1975 which was tabled before the Ontario Energy Board hearing in 1975, indicates that the discount for Interruptible 'A' is too low and the discounts for Interruptible 'B' and Schedule 'C' power are too high. The Interruptible 'A' discount is being increased from 85¢ per kilowatt per month to 95¢ per kilowatt per month while the Interruptible 'B' and Schedule 'C' power discounts are unchanged from those applicable in 1979.

10. Furnace rates are no longer offered to new customers and the rates to existing customers are being phased out to regular rates. The phasing-out process, which began in 1977, has been extended from three to five years as recommended by the Ontario Energy Board and will be completed by January 1, 1982. The furnace rates have been established to reflect the overall increase plus approximately 4.2 per cent. The rates are set out in table 6B3.

Electric furnace rates **Table 6B3**

¢/kW•h

	Monthly hours' use of billing demand			
	First 100	Next 100	Next 300	Balance
230 kV				
Approved for 1979	3.72	1.74	1.65	1.12
Proposed for 1980	4.60	1.73	1.62	1.21
115 kV				
Approved for 1979	3.74	1.76	1.68	1.12
Proposed for 1980	4.62	1.75	1.65	1.21
10 to 50 kV				
Approved for 1979	3.80	1.82	1.74	1.12
Proposed for 1980	4.71	1.84	1.74	1.21
Under 10 kV				
Approved for 1979	3.86	1.88	1.80	1.12
Proposed for 1980	4.77	1.90	1.80	1.21
Discounts (1980)				
Interruptible "A"	.19	.19	.19	—
Interruptible "B"	.24	.24	.24	—

Minimum monthly bill – per kW of billing demand

	Firm	Int. "A"
for 1979 & 1980	$1.50	$1.00

11. Ontario Hydro supplies power to three companies which distribute power. Of these, the Gananoque Electric Light and Water Supply Company Ltd. and the Great Lakes Power Corporation, distribute power in Ontario. The third customer, Boise Cascade Canada Ltd., located in Fort Frances, exports power to its parent company Boise-Cascade Corp. in International Falls, Minnesota, under License #EL-62 granted by the National Energy Board. As each of these companies generates some of its power requirements, each agreement includes provision for Standby Service. In addition, the agreement with the Great Lakes Power Corporation includes provisions which recognize the reciprocal benefits of the interconnection between the Ontario Hydro and the Great Lakes Power Systems. Rates applicable to these three customers are shown in table 6B4.

12. In the case of Great Lakes Power Corporation and the Gananoque Electric Light and Water Supply Company Ltd., the rates charged by Ontario Hydro are based on cost functions applicable to municipalities under corresponding conditions of supply plus a margin of 5%. The rates chargeable to Boise Cascade Canada Ltd. for export power are subject to the stipulation of the National Energy Board that the border price shall not be less than 120% of the standard rate applicable to direct customers of Ontario Hydro. This price is computed in mills per kilowatt-hour at the monthly load factor of export power.

13. The application of these rate schedules is estimated to increase revenue from the Direct Customer class by 7.8% over the amount that would have been obtained at existing rates. The estimated percentage increase to direct customers, including the effect of special conditions of supply (such as interruptible power) as applicable, but excluding any effect of anti-inflation rebate, is summarized in table 6B5.

Distributing companies		Table 6B4
	Approved for 1979	Proposed for 1980
Gananoque E.L. & W.S. – supplied at 44 kV		
Demand rates		
Firm power – per kW per month	$6.60	$7.40
Standby service – per kW per month	.93	1.07
Standby power – per kW per day	.26	.31
Energy (per kW•h)	1.12¢	1.21¢
Great Lakes Power Corp. – supplied at 230 kV		
Demand rates		
Firm power – per kW per month	$6.08	$6.71
Standby service – per kW per month	.74	.76
Supplementary – per kW per day	.25	.28
Energy (per kW•h)	1.12¢	1.21¢
Boise Cascade Canada Ltd. (export) – supplied at 115 kV		
Demand rates		
Firm power – per kW per month	$5.84	$6.21
Standby service – per kW per month	.89	.91
Energy (per kW•h)	1.35¢	1.45¢

Customer impact		Table 6B5
	Number of Customers	
% Increase	in interval	Cumulative
6.5-7.0	12	12
7.1-7.5	39	51
7.6-8.0	11	62
8.1-8.5	30	92
8.6-9.0	7	99
over 9.0	10	109

Chapter 6
PROPOSED RATES

C. Revenues

Summary of revenues — **Table 6C1**

$ millions

	Actual*	Forecast		
	1978	1979	1980	1981
Municipal utilities	**1276**	1410	1591	1902
Direct customers	**262**	316	364	454
Allocation of bulk power cost to rural customers	**292**	324	360	452
Total bulk power revenue	**1830**	2050	2315	2808

*Includes 1978 excess revenue

Forecast revenue – municipal utilities — **Table 6C2**

Rates and Charges	Forecast Billing Quantities 1980	Level of Monthly Rates and Charges		Forecast Revenue for 1980 at (M$)	
		1979	1980	1979 Rates	1980 Rates
Demand rate					
– over 50 kV	414,500 kW	6.19 ($/kW)	6.70 ($/kW)	30.8	33.3
– 10 to 50 kV	9,473,000 kW	6.57	7.24	746.9	823.0
– under 10 kV	222,400 kW	6.95	7.61	18.6	20.3
	10,109,900 kW				
Energy rate	63,913,400 MW•h	1.02 (¢/kW•h)	1.12 (¢/kW•h)	651.9	715.8
Specific facilities	$4,009,031 of capital	1.308%	1.441%	.6	.7
Ownership of LV switchgear	2,143,300 kW	.06 ($/kW)	.08 ($/kW)	(1.5)	(2.0)
Standby	3,700 kW	.93 ($/kW)	1.07 ($/kW)	—	—
Total				1,447.3	1,591.1

Average increase in bulk power rate – 9.9%

Forecast revenue – direct customers

Table 6C3

MAIN SERVICE CLASSIFICATION		Level of Rates and Charges		Forecast Revenue for 1980 at ($000's)	
Class of Power	Forecast Billing Quantities 1980	1979	1980	1979 Rates	1980 Rates
230 kV Firm	5,165,364 kW	$4.74	$5.03	$24.484	$25,982
Int. A	403,632 kW	3.89	4.08	1,570	1,647
Int. B	529,152 kW	3.55	3.84	1,878	2,032
115 kV Firm	10,937,232 kW	4.87	5.16	53,264	56,436
Int. A	746,736 kW	4.02	4.21	3,002	3,143
Int. B	460,860 kW	3.68	3.97	1,696	1,830
Schedule C	124,500 kW	3.44	3.73	428	464
10-50 kV Firm	4,509,276 kW	5.17	5.60	23,313	25,252
Int. A	1,102,668 kW	4.32	4.65	4,764	5,127
Int. B	1,697,208 kW	3.98	4.41	6,755	7,485
Under 10 kV Firm	227,052 kW	5.47	5.91	1,242	1,342
Main class energy	15,214,176 MW•h	1.12¢	1.21¢	170,399	184,092
				292,795	314,832
DISTRIBUTING COMPANIES*					
Gananoque Boise Cascade Canada Ltd. (Export) Great Lakes Power	2,354,196 kW 1,539,047 MW•h			31,689	34,448
AUXILIARY SERVICE CLASSIFICATION					
Electric furnaces	1,919,892 kW and 555,908 MW•h			12,300	13,761
Standby service					
	91,200 kW	$ .90	$ .98	82	89
	547,200 kW	.74	.76	405	416
	48,000 kW	.89	.91	43	44
	15,000 kW	.93	1.07	14	16
				544	565
Total direct customer revenue				337,328	363,606

Average increase in bulk power rate – 7.8%

*Distributing Companies' rates are shown in Table 6B4

Chapter 7
FINANCIAL RESULTS

A. Financial Statements – Forecast

1. Financial Forecast 790420 represents a quantification of the organization's plans and activities as of April 20, 1979 and has been approved by the Ontario Hydro Board as the most appropriate base for establishing the bulk power revenue requirement for 1980. Except for table 7A2 which relates the revenue requirement components shown in table 5A2, to the Statement of Operations, the following statements are extracted from the financial forecast.

Statement of operations for the years ending December 31 — **Table 7A1**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Revenues				
Primary power and energy	**1,979**	2,208	2,482	2,995
Secondary power and energy	**289**	294	291	202
	2,268	2,502	2,773	3,197
Less excess revenue	**130**	—	—	—
	2,138	2,502	2,773	3,197
Costs				
Operation, maintenance and administration	**502**	600	600	657
Fuels used for electric generation	**487**	652	733	719
Power purchases	**98**	84	104	93
Commissioning energy	**22**	4	4	15
Nuclear agreement – payback	**47**	52	64	65
Depreciation*	**265**	314	345	391
	1,421	1,706	1,850	1,940
Income before interest	**717**	796	923	1,257
Interest	**549**	671	712	800
Income before extraordinary item	**168**	125	211	457
Extraordinary item	**21**	—	—	—
Net income	**147**	125	211	457
Amounts appropriated for:				
Debt retirement	**113**	135	156	175
Stabilization of rates and contingencies	**34**	(10)	55	282
	147	125	211	457

*Includes amortization of capital costs of deferred projects

Revenue requirement components traced to statement of operations

Table 7A2

$ millions

Revenue requirement (forecast for 1980)	Bulk Power (table 5A2)	Retail Costs*	Statement of operations (table 7A1) for the year ending December 31, 1980	
Operations, maintenance and administration	509	79		
Property taxes	15			
Water rentals	20			
Internal sales	(23)			
	521	79	Operations, maintenance and administration	600
Fuel	761		Fuels used for electric generation	733
Commissioning	4		Commissioning energy	4
Bruce steam transfer	(28)			
	737			737
Power purchases	104		Power purchases	104
Nuclear agreement – payback	64		Nuclear agreement – payback	64
Depreciation	320	25	Depreciation	345
Interest	668	44	Interest	712
Debt retirement	147	9	Debt retirement	156
Stabilization of rates	45	1		
Deficit recovery	—	9		
	45	10	Stabilization of rates and contingencies	55
Less: Secondary revenue	(291)		Less: Secondary power and energy	(291)
	2,315	167		2,482

*Statement of Costs, Financial Forecast 790420

Statement of financial position for the years ending December 31 — **Table 7A3**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
ASSETS				
Fixed assets				
Fixed assets in service, at cost	**9,549**	11,133	12,063	13,572
Less accumulated depreciation	**1,859**	2,140	2,456	2,843
	7,690	8,993	9,607	10,729
Fixed assets under construction	**3,651**	3,797	4,543	4,983
	11,341	12,790	14,150	15,712
Current assets				
Cash and short-term investments	**693**	604	554	566
Accounts receivable	**255**	300	310	360
Fuel for electric generation, at cost	**410**	475	507	574
Materials and supplies, at cost	**112**	136	153	173
	1,470	1,515	1,524	1,673
Other assets				
Investments	**59**	54	37	32
Debt discount and expense, less amounts written off	**106**	122	136	150
Advance payments for fuel supplies	**141**	303	453	592
Long-term accounts receivable and other assets	**46**	54	86	84
	352	533	712	858
	13,163	14,838	16,386	18,243
LIABILITIES				
Long-term debt				
Bonds and notes payable	**10,129**	11,719	13,031	14,387
Other long-term debt	**270**	250	240	229
	10,399	11,969	13,271	14,616
Less payable within one year	**172**	371	357	463
	10,227	11,598	12,914	14,153
Current liabilities				
Accounts payable and accrued charges	**513**	587	609	635
Short-term notes payable	**25**	25	25	25
Accrued interest	**274**	305	341	375
Long-term debt payable within one year	**172**	371	357	463
Excess revenue payable	**132**	—	—	—
Estimated liability on cancellation of capital construction projects	**17**	25	5	—
	1,133	1,313	1,337	1,498
EQUITY				
Equities accumulated through debt retirement appropriations	**1,391**	1,525	1,677	2,852
Reserve for stabilization of rates and contingencies	**285**	275	331	613
Contributions from the Province of Ontario as assistance for rural construction	**127**	127	127	127
	1,803	1,927	2,135	2,592
	13,163	14,838	16,386	18,243

Reserve for stabilization of rates and contingencies for the years ending December 31 — Table 7A4

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
Summary of change in reserve balance				
Balance at beginning of year	**250**	285	275	331
Retail deficit recovered on annexation	**1**	—	1	—
Appropriated from net income	**34**	(10)	55	282
Balance at end of year	**285**	275	331	613
Year-end balance by class of customer				
All customers	**315**	304	340	605
Municipalities	**1**	1	1	1
Direct customers	**(4)**	—	—	—
Retail customers	**(32)**	(32)	(23)	(14)
Retail customers – equity	**7**	12	13	21
All customers – non common	**(2)**	(10)	—	—

Statement of changes in financial position for the years ending December 31 **Table 7A5**

$ millions

	Actual	Forecast		
	1978	1979	1980	1981
SOURCE OF FUNDS				
Operations				
Net income before extraordinary items	**168**	125	211	457
Depreciation*	**265**	314	345	392
	433	439	556	849
Financing				
Bonds and long-term notes issued	**1,837**	1,891**	1,750	1,800
Less retirements	**347**	321**	448	455
	1,490	1,570	1,302	1,345
Short-term notes – increase (decrease)	**(20)**	—	—	—
Cash and investments – (increase) decrease	**(236)**	94	67	(7)
Excess revenue – increase (decrease)	**11**	(132)	—	—
Increase (decrease) in accounts and interest payable including estimated liability on cancellation of capital construction projects	**150**	113	38	55
	1,828	2,084	1,963	2,242
APPLICATION OF FUNDS				
Net expenditures on fixed assets	**1,652**	1,763	1,705	1,954
Extraordinary item – loss on cancellation of projects	**21**	—	—	—
Increase in advance payments for fuel supplies	**45**	162	150	139
Increase (decrease) in fuel, materials and supplies	**65**	89	49	87
Increase in accounts receivable and other assets	**45**	70	59	62
	1,828	2,084	1,963	2,242

* Includes amortization of capaital costs of deferred projects.
**$1,845 million derived through Corporate Financing program.
Balance of $46 million results from refinancing a Deutsche Mark serial bond issue.
Early retirement of Deutsche Mark issue accounts for $46 million of retirements.

B. Financial Forecast Performance

B. Financial Forecast Performance

1. Table 7B1 illustrates the actual bulk power cost per kilowatt for the years 1975-1978 and forecast costs since 1974 when proposed bulk power rates were first reviewed by the Ontario Energy Board. Costs include statutory debt retirement charges but not provisions to, or withdrawls from the Reserve for Stabilization of Rates and Contingencies.

- Accuracy deteriorates in the second forecast year to an average of 9.2%.

3. Chart 7B2 compares the bulk power cost per kilowatt with the forecast used to set bulk power rates since 1970.

4. Steps are continually being taken to improve the accuracy of the forecast but it is still subject to many uncertainties. The major variables which contribute to the forecast inaccuracies are

Bulk power cost comparisons* – forecast versus actual — **Table 7B1**

$/kW

		Year of Forecast					
	Actual	1974	1975	1976	1977	1978	1979
1975	82.86	71.99					
1976	94.84	84.61	92.11				
1977	105.47	99.08	115.66	114.38			
1978	119.31	108.91	127.19	127.86	126.71		
1979		120.70	139.84	136.89	139.23	139.17	
1980			154.97		148.42	143.84	157.44
1981					160.58	153.23	171.02
1982					174.28	165.38	181.20
1983						175.68	190.63
1984							205.70

Forecast Error — %

	Year of Forecast			
	1974	1975	1976	1977
1975	13.12			
1976	10.79	2.88		
1977	6.06	(9.66)	(8.45)	
1978	8.72	(6.60)	(7.17)	(6.20)

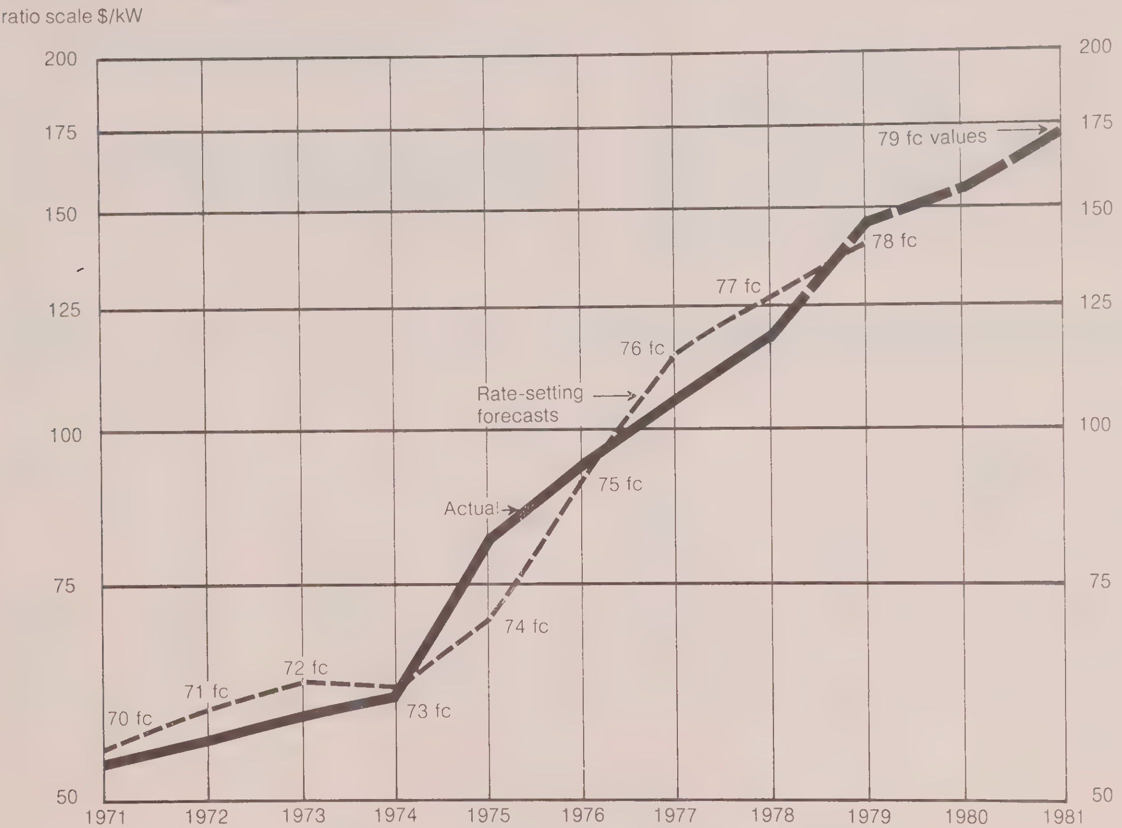
*Including Debt Retirement Charges but excluding provisions to or withdrawals from the Reserve for Stabilization of Rates

2. The data in table 7B1 indicate the following

- Forecast errors in the first forecast year (rate year) have averaged 7.7% for the four-year period beginning in 1974 and 5.8% for the last three years.

- changes in load forecast
- secondary revenues and associated costs which vary substantially
- changes in in-service dates for generation and transmission facilities

Bulk power cost per kilowatt* — actual versus forecast Table 7B2



*Including debt retirement charges but excluding Stabilization of Rates

- variations in output from nuclear stations, variations in hydraulic output due to stream-flow fluctuations, and variations in availability of power purchases, all of which affect fossil-thermal energy production
- effects of foreign exchange

Ontario Hydro
700 University Avenue
Toronto, Ontario
M5G 1X6

Robert B. Taylor, Chairman of the Board

Appendix 1

April 30, 1979

Honourable James Auld
Minister of Energy
12th Floor
56 Wellesley Street, West
TORONTO, Ontario. M7A 2B7

Dear Mr. Minister:

In accordance with section 37a of The Ontario Energy Board Act, Ontario Hydro hereby submits to you its proposal to change its bulk power rates to its municipal utility and direct industrial customers, effective January 1, 1980.

The proposed rates are set out in two attached documents:

(A) Proposed 1980 Wholesale Rates for Municipal Corporations and Municipal Electric Utility Commissions;

(B) Proposed 1980 Rates for Direct Industrial Customers having an average annual power demand of 5000 kilowatts or more.

In formulating the rate proposal, the Board has proceeded on the basis that the rate increase should be held to an absolute minimum short of any further deterioration of financial soundness beyond the level now forecast for the end of 1979, namely, a debt ratio of .862. This means that in order to cover the expected cost increases, an average bulk power rate increase of 9.5% is necessary, broken down as follows:

Municipal Utility Rates - The proposed rate increase to each of the 332 municipal utilities would vary according to the utility's demand, its energy use,

and supply conditions, averaging about 9.9%. For the three-year period 1978-1980 the increase would average 9.7% per year.

The increase in wholesale rates in 1980 would probably result in the majority of municipal utilities increasing their retail rates during 1980. The amount will vary from utility to utility and will depend, in part, upon their need to cover increases in their own costs.

Direct Industrial Rates - The proposed average increase for the approximately 100 large industrial customers is 7.8%, based on the estimated peak and energy demands for 1980. For the three-year period 1978-1980 the increase would average 9.4% per year.

This represents the first time since The Ontario Energy Board Act was revised in 1974 to include bulk power rates that the increase for large industrial customers will be less than the increase for municipal utilities. With the exception of 1976, the year for which rate increases were fixed at the same percentage for both classes, the differential in the period 1975 through 1979 has ranged from .3% to 2.8% higher for the large industrial customers. In 1980, the factors which cause this differential have combined to move it 2.1% in the other direction.

The difference between the proposed municipal and industrial rate increases arises from the following cost factors attributable to these two classes of customer: the change in coincidence of large industrial loads; the elimination of the deficit pertaining to the large industrial class; the proportionate use of common and non-common facilities; and the mix of firm and interruptible power.

Costs and Revenues

Of the $265 million in total bulk power cost increase in 1980, only about $65 million in fuel costs is associated with additional energy requirements. The remaining $200 million is related to the following principal factors:

Fuels and Related Costs - An increase of $52 million. This is primarily due to higher prices for coal and other fuels, and purchased power.

Fixed Charges - An increase of $70 million. Interest and depreciation costs increase as a result of bringing new facilities into service. In addition there are increased charges to current operations for interest and amortization costs mainly associated with the storing of an Enricher unit at the Bruce Heavy Water Plant "D" in 1980.

Net Income - An increase of $80 million. Net income is required to meet statutory debt retirement obligations and to assist in financing the capital construction program. The proposed level of net income will result in an interest coverage of 1.18 and a debt ratio of .862, and is less than is required to meet Ontario Hydro's targets of a debt ratio ranging from .80 to .82 and an interest coverage of 1.35. This increase of $80 million reflects the considerable shortfall in net income now estimated for 1979 from the level expected when the rates for 1979 were set.

While recognizing the precedence which must be given to restraint in the face of a continued high rate of general inflation, the Hydro Board is very much concerned that the level of financial integrity which Ontario Hydro has felt to be prudent and which has been supported by both your Ministry and the Ontario Energy Board will not be achieved. I wish to assure you that every effort will be made in the future to improve this projected financial picture.

Sincerely,

ON BEHALF OF THE BOARD

Encs.

cc - Members of the Board
Mr. M. Rowan

Attachment A

Proposed 1980 Wholesale Rates for Municipal

Corporations and Municipal Electric

Utility Commissions

Attachment A

MUNICIPAL ELECTRIC UTILITIES
1980 SCHEDULE OF MONTHLY BILLING RATES

	Over 50 kV	10 kV to 50 kV	Less than 10 kV
Demand Billing Rate ($ per kW)	6.70	7.24	7.61
Energy Rate (cents per kWh)	1.12	1.12	1.12
Other Charges and Credits			
Specific Facility Charge (% of capital)	-	1.441	1.441
Ownership of Low Voltage Switchgear Credit ($ per kW)	-	0.08	-
Standby Charge ($ per kW)	-	1.07	-

<u>Attachment B</u>

Proposed 1980 Rates for Direct Industrial Customers with an average annual power demand of 5000 kilowatts or more.

Rates for

Direct Customers in 1980

1. Standard Rates

(a) Demand Rates - per kW of billing demand per month

Class of Power		Approved for 1979	Proposed for 1980
230 kV	- Firm	$4.74	$5.03
	- Interruptible "A"	3.89	4.08
	- Interruptible "B"	3.55	3.84
	- Schedule "C"	3.32	3.60
	- Scheduled-Hour Class 1	1.43	1.75
	Class 2	0.87	1.07
	- Excess	5.93	6.29
	- Standby Service	0.74	0.76
115 kV	- Firm	4.87	5.16
	- Interruptible "A"	4.02	4.21
	- Interruptible "B"	3.68	3.97
	- Schedule "C"	3.44	3.73
	- Scheduled-Hour Class 1	1.56	1.91
	Class 2	0.95	1.17
	- Excess	6.09	6.45
	- Standby Service	0.74	0.76
10 to 100 kV	- Firm	5.17	5.60
	- Interruptible "A"	4.32	4.65
	- Interruptible "B"	3.98	4.41
	- Schedule "C"	3.75	4.17
	- Scheduled-Hour Class 1	1.72	2.06
	Class 2	1.05	1.26
	- Excess	6.46	7.00
	- Standby Service	0.90	0.98
Under 10 kV	- Firm	5.47	5.91
	- Interruptible "A"	4.62	4.96
	- Interruptible "B"	4.28	4.72
	- Excess	6.84	7.39
(b) Energy Rate - per kWh		1.12¢	1.21¢

Rates for

Direct Customers in 1980

2. Electric Furnace Rates

	Monthly Hours' Use of Billing Demand - Cents/kWh			
	First 100	Next 100	Next 300	Balance
230 kV				
Approved for 1979	3.72	1.74	1.65	1.12
Proposed for 1980	4.60	1.73	1.62	1.21
115 kV				
Approved for 1979	3.74	1.76	1.68	1.12
Proposed for 1980	4.62	1.75	1.65	1.21
10 to 100 kV				
Approved for 1979	3.80	1.82	1.74	1.12
Proposed for 1980	4.71	1.84	1.74	1.21
Under 10 kV				
Approved for 1979	3.86	1.88	1.80	1.12
Proposed for 1980	4.77	1.90	1.80	1.21
Discounts (1980)				
Interruptible "A"	.19	.19	.19	-
Interruptible "B"	.24	.24	.24	-

Minimum Monthly Bill - per kW of Billing Demand

	Firm	Int. "A"
for 1979 & 1980	$1.50	$1.00

Rates for
Direct Customers in 1980

3. Distributing Companies

Ganonoque Light & Power Co. Ltd. - supplied at 44 kV

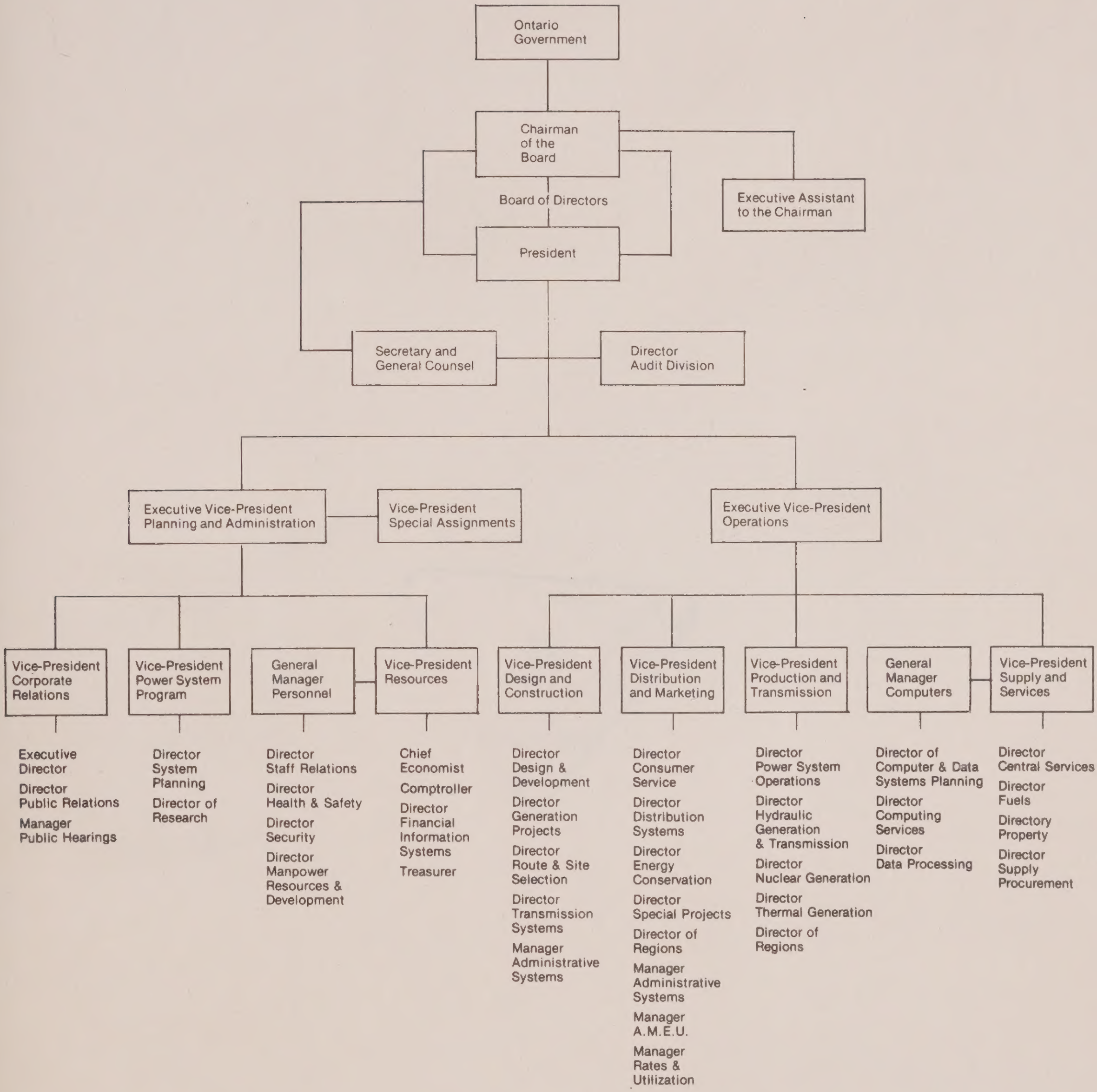
	Approved for 1979 $	Proposed for 1980 $
(a) Demand Rates		
Firm Power - per kW per month	6.60	7.40
Standby Service - per kW per month	0.93	1.07
Standby Power - per kW per day	0.26	0.31
(b) Energy - per kWh	1.12¢	1.21¢

Great Lakes Power Corp. - supplied at 230 kV

	Approved for 1979 $	Proposed for 1980 $
(a) Demand Rates		
Firm Power - per kW per month	6.08	6.71
Standby Service - per kW per month	0.74	0.76
Supplementary - per kW per day	0.25	0.28
(b) Energy - per kWh	1.12¢	1.21¢

Boise Cascade Canada Limited (Export) - supplied at 115 kV

	Approved for 1979 $	Proposed for 1980 $
(a) Demand Rates		
Firm Power - per kW per month	5.84	6.21
Standby Service - per kW per month	0.89	0.91
(b) Energy - per kWh	1.35¢	1.45¢


Ontario Government
Chairman of the Board
Executive Assistant to the Chairman
Board of Directors
President
Secretary and General Counsel
Director Audit Division
Executive Vice-President Planning and Administration
Vice-President Special Assignments
Executive Vice-President Operations
Vice-President Corporate Relations
Vice-President Power System Program
General Manager Personnel
Vice-President Resources
Vice-President Design and Construction
Vice-President Distribution and Marketing
Vice-President Production and Transmission
General Manager Computers
Vice-President Supply and Services
Executive Director
Director Public Relations
Manager Public Hearings
Director System Planning
Director of Research
Director Staff Relations
Director Health & Safety
Director Security
Director Manpower Resources & Development
Chief Economist
Comptroller
Director Financial Information Systems
Treasurer
Director Design & Development
Director Generation Projects
Director Route & Site Selection
Director Transmission Systems
Manager Administrative Systems
Director Consumer Service
Director Distribution Systems
Director Energy Conservation
Director Special Projects
Director of Regions
Manager Administrative Systems
Manager A.M.E.U.
Manager Rates & Utilization
Director Power System Operations
Director Hydraulic Generation & Transmission
Director Nuclear Generation
Director Thermal Generation
Director of Regions
Director of Computer & Data Systems Planning
Director Computing Services
Director Data Processing
Director Central Services
Director Fuels
Directory Property
Director Supply Procurement